PUBLIC VERSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 190

In the Matter of	)
	)
Biennial Consolidated Carbon Plan	)
and Integrated Resource Plan of	)
Duke Energy Carolinas, LLC and	)
Duke Energy Progress, LLC,	)
Pursuant to N.C.G.S. § 62-110.9	)
and § 62-110.1(c)	)

DIRECT TESTIMONY AND EXHIBITS OF

MICHAEL GOGGIN

ON BEHALF OF

THE SOUTHERN ALLIANCE FOR CLEAN ENERGY, THE SIERRA CLUB, THE NATURAL RESOURCES DEFENSE COUNCIL, AND THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

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TABLE OF CONTENTS

I. Introduction 3

II. Duke can use a range of solutions to more quickly interconnect new renewable and battery resources 9

III. Duke should reduce or eliminate its assumed wind and solar generic transmission network upgrade proxy costs 34

IV. Duke should expeditiously use proactive multi-value transmission planning to build needed grid upgrades 43

V. The Commission should require Duke to evaluate expanding ties to neighboring grid operators 57

VI. Increasing Duke's dependence on gas generation exposes ratepayers to reliability and economic risks 65

EXHIBITS

MG-1	**Curriculum Vitae of Michael Goggin**
MG-2	**Duke's response to SACE DR 32-4**
MG-3	**Duke's response to SACE DR 31-1 (CONFIDENTIAL)**
MG-4	**Duke Energy, Presentation: 2024 Multi-Value Strategic Transmission Study (April 2024)**
MG-5	**Duke's response to Public Staff DR 40-1(a)**
MG-6	**PSDR 1-7 CONFIDENTIAL_Updated with Phase II Study Results - Trans Cost Assumptions DEC and DEP 2023v1_SPA (CONFIDENTIAL)**
MG-7	**Duke's response to SACE DR 33-2**
MG-8	**Duke's response to SACE DR 27-2-2**

I. Introduction

Q: PLEASE STATE YOUR NAME AND JOB TITLE.

A: My name is Michael Goggin, and I am Vice President at Grid Strategies, LLC, a consulting firm based in the Washington, D.C. area.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A: I am testifying on behalf of the Southern Alliance for Clean Energy (SACE), the Sierra Club, and the Natural Resources Defense Council (NRDC), as represented by the Southern Environmental Law Center, and on behalf of the North Carolina Sustainable Energy Association (NCSEA).

Q: HAVE YOU EVER TESTIFIED BEFORE PUBLIC UTILITY COMMISSIONS OR REGULATORY BODIES?

A: Yes, I have testified before public utility commissions in Arizona, Colorado, Georgia, Illinois, Indiana, Iowa, Kentucky, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Virginia, Washington, and Wisconsin, as well as before the Federal Energy Regulatory Commission (FERC).

Q: IN WHICH CASES HAVE YOU TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION (NCUC)?

A: I testified last year in the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) (collectively, Duke Energy or Duke) Multi-Year Rate Plan cases in NCUC Docket Nos. E-7, Sub 1276, and E-2, Sub 1300, respectively.

Q: PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A: I have worked on transmission and renewable energy issues for nearly two decades. At Grid Strategies, LLC, I have served as an expert on these topics for a range of clients over the last six years, including state utility regulators and grid operators. For the preceding ten years, I was employed by the American Wind Energy Association (AWEA), now known as the American Clean Power Association, where I provided technical analysis and advocacy on renewable energy and transmission matters. This included directing AWEA's research and analysis team from 2014–2018. Prior to that, I was employed at a firm serving as a consultant to the U.S. Department of Energy and two environmental groups.

Over the course of my career, I have co-authored over one hundred filings to FERC; served as a technical reviewer for over a dozen national laboratory reports, academic articles, and renewable integration studies; and published academic articles and conference presentations on renewable energy, transmission, and policy. I have also served as an elected member of the Standards, Planning, and Operating Committees of the North American Electric Reliability Corporation (NERC). I hold an undergraduate degree with honors from Harvard University. A copy of my Curriculum Vitae is attached as **Exhibit MG-1**.

Q: PLEASE SUMMARIZE YOUR TESTIMONY.

A: My testimony primarily focuses on the transmission-related aspects of Duke Energy's proposed Carbon Plan and Integrated Resource Plan (CPIRP), and finds they fall short in critical ways that the Commission can address by implementing the following recommendations. I also explain how renewable and storage resources provide better economic and reliability value for Duke ratepayers than its proposed gas generators.

First, the proposed CPIRP overstates the challenges associated with interconnecting new generating resources. Even under Duke's conservative assumptions, the transmission outages required to interconnect new generators would comprise a manageably small share of total transmission outages. Other grid operators are successfully interconnecting new renewable and storage resources at a significantly faster rate than Duke's claimed interconnection limit. I offer a number of solutions Duke can use to more quickly and efficiently interconnect new resources.

Second, the proposed CPIRP's assumed generic transmission network upgrade cost adders for wind and solar resources in DEC's footprint are too high, and do not account for the benefits of those transmission upgrades. I recommend that the assumed costs for DEC should be replaced with the lower costs assumed for DEP, which are [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Duke's higher assumed upgrade costs for DEC bias its economic resource optimization against selecting wind and solar resources.

Third, I explain that the proposed "Red Zone Transmission Expansion Plan" (RZEP) 2.0 projects are essential for cost-effectively meeting Duke's carbon reduction requirements, and provide other economic and reliability benefits. However, a much larger additional transmission expansion will be essential for meeting Duke's needs. RZEP 2.0 only meets about 11% of the transmission need identified through Duke's 2023 Public Policy Study. As a result, there is an urgent need for further transmission expansion, including higher-voltage transmission, greenfield projects, and expanded transmission ties to neighbors; all of which can be most efficiently planned with proactive multi-value transmission planning. My testimony then outlines the steps Duke and the Commission should take to adopt proactive multi-value methods to plan and build the needed transmission. The best practice is a proactive synchronized generation and transmission plan that maximizes net benefits across all value streams of transmission, as other utilities and regions have found this to be the most effective and beneficial method for planning transmission. Proactive synchronized planning of generation and transmission will lead to lower overall costs for Duke's customers compared to reactive generation-driven transmission investment. Transmission planning must be synchronized with generation planning for it to truly be an "integrated" resource plan that will reliably serve customers at least cost. The Carolinas Transmission Planning Collaborative's (CTPC) new Multi-Value Strategic Transmission (MVST) planning category appears to be a strong first step in this direction, but the methods can be further refined, and the Commission must direct Duke to use the MVST process to plan and build the needed transmission.

Fourth, in the CTPC's MVST proactive multi-value transmission planning analysis discussed above, the Commission should require Duke to plan and build stronger transmission ties with neighboring Balancing Authorities, as well as between DEC and DEP, which Duke expects to have merged by January 2027.[1] Expanding these ties is essential for increasing reliability and resilience while reducing Duke's needed planning reserve margin, and cost-effectively meeting future needs including Duke's carbon reduction requirements. The Commission should require Duke to bring net beneficial tie expansion projects to the Commission for approval and negotiate cost allocation with neighboring utilities to reflect the benefits they also receive from these upgrades. The Commission should also direct Duke to propose and advocate for the Southeastern Regional Transmission Planning (SERTP) process to conduct synchronized proactive multi-value transmission planning using reasonable assumptions that accurately reflect the value of transmission. The Commission should also advocate for SERTP and its participating states and utilities to adopt a workable cost allocation mechanism for the transmission projects identified in those planning studies. FERC Order 1920 provides a foundation for implementing these region-wide planning and cost allocation reforms, which are essential for ensuring North Carolina ratepayers have affordable and reliable electric service.

[1] Duke Proposed CPIRP, Ch.4, p.38.

Finally, I compare the reliability and economic value of renewable and storage resources relative to Duke's proposed gas generators. First, I note the reliability risks from correlated gas generator outages, like those experienced during Winter Storm Elliott and other recent cold snaps. Second, I explain how flexible battery resources are far more valuable than gas generators for managing power system variability. Finally, I explain how increasing Duke's dependence on gas generation expands its exposure to fuel price risk and future environmental regulations.

Q: PLEASE IDENTIFY THE EXHIBITS TO YOUR TESTIMONY.

A: My testimony includes the following exhibits:

Exhibit MG-1	Curriculum Vitae of Michael Goggin.
Exhibit MG-2	Duke's response to SACE DR 32-4.
Exhibit MG-3	Duke's response to SACE DR 31-1 (CONFIDENTIAL).
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II. Duke can use a range of solutions to more quickly interconnect new renewable and battery resources

Q: WHAT DOES DUKE ASSUME REGARDING THE RATE AT WHICH IT CAN INTERCONNECT NEW SOLAR AND BATTERY RESOURCES?

A: The modeling in Duke's CPIRP contains an annual limit on solar installations of "1,350 MW/year starting in 2028 and increasing to 1,575 MW/year starting in 2031," with an increase "to 1,800 MW per year across DEC and DEP starting in 2032 and beyond."[2] Duke also explains that "selection of additional stand-alone battery storage resources (beyond those already forecast for availability) was limited to 1) 200 MW for 2027, 2) 500 MW per year for 2028-29, and 3) 1,000 MW for 2030 and beyond."[3] These limits are summarized in Table 1.

Table 1: Duke's annual interconnection limits for new solar and batteries (in MW)

	Solar limit	Battery limit	Combined limit
2027	0	200	200
2028	1,350	500	1,850
2029	1,350	500	1,850
2030	1,575	1,000	2,575
2031	1,575	1,000	2,575
2032 and beyond	1,800	1,000	2,800

[2] Duke Proposed CPIRP, Supp. Planning Analysis at 25.

[3] *Id.* at 26.

Q: WHAT JUSTIFICATION DOES DUKE OFFER FOR ITS PROPOSED LIMITS?

A: Duke points to challenges related to interconnection, including increasingly complex interconnections and challenges in coordinating transmission outages necessary to interconnect new resources. For example, Duke states that "Outage coordination groups currently accommodate about as many outages as can be accommodated and maintain reliable, single contingency operations in accordance with NERC Reliability Standards and prudent outage planning."[4] These claims are addressed below.

Q: HOW DO DUKE'S LIMITS COMPARE TO THE RATE AT WHICH OTHER GRID OPERATORS HAVE BEEN ABLE TO INTERCONNECT NEW SOLAR AND STORAGE RESOURCES?

A: The much higher rate at which other grid operators have been able to interconnect new solar and storage resources indicates there are solutions to Duke's claims about interconnection limits. As shown in Table 2 below, over the last three years the California Independent System Operator (CAISO) has averaged 85 utility-scale solar and/or battery interconnections per year, adding an average of 4,474 MW annually.[5] CAISO's peak load is 42% greater than Duke's, but it is possible to normalize CAISO's figures to find a comparable

[4] Duke Proposed CPIRP, App'x L at 21.
[5] EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)* (May 23, 2024), https://www.eia.gov/electricity/data/eia860m/.

average for Duke as a share of peak load. This analysis suggests that Duke could interconnect around 60 projects or 3,146 MW annually if it matched CAISO's average interconnect rate. Using CAISO's highest single-year interconnection rates of 101 projects in 2021 or 5,625 MW in 2023 suggests Duke could interconnect 71 projects or 3,955 MW of solar and storage per year. The Electric Reliability Council of Texas (ERCOT) has similarly averaged over 8,900 MW of interconnections across all resource types over the last three years, with a maximum of 10,107 MW in 2021.[6] Given that ERCOT's peak load is more than twice that of Duke's, these figures translate to Duke being able to interconnect an average of over 3,800 MW annually and a maximum of more than 4,300 MW per year.

As shown in Table 1 above, Duke assumed it would be limited to adding 1,850 MW/year of solar and batteries in 2028 and 2029, 2,575 MW annually in the 2030 and 2031, and 2,800 MW/year after that. On a load-normalized MW/year basis, CAISO's solar and battery interconnection rate last year was 2.14 times greater than what Duke has assumed is feasible in 2028 and 2029, 54% greater than Duke's limit in 2030 and 2031, and 41% greater than Duke's assumed limit in 2032 and beyond. CAISO's interconnection rate also increased by 1,254 MW/year in 2022 and 1,099 MW in 2023, confirming that there are solutions for increasing interconnection rates over time.

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[6] *Id.*

Table 2: CAISO solar and/or storage interconnection rate for 2021-2023[7]

	Projects	MW
2023	69	5,625
2022	84	4,526
2021	101	3,272
Average	85	4,474

The far higher rate at which CAISO has been able to interconnect new solar and storage resources relative to what Duke claims is possible indicates that Duke's concerns can be overcome. For several reasons, CAISO's recent interconnection rate should be conservative relative to what Duke can achieve. Duke's solar interconnections have tended to be on lower-voltage lines relative to those in CAISO, which should make outage coordination easier as removing these lines from service tends to have a smaller impact on the overall transmission system. Many solar interconnections on CAISO's transmission system have also tended to be on longer lines that traverse sparsely populated areas, where there is less of a meshed network to provide redundancy when a line is taken out of service, in contrast to Duke's system. In addition, CAISO and its utilities have been taking a large number of transmission outages for wildfire mitigation upgrade projects,[8] so its rapid interconnection rate indicates it has been able to successfully coordinate those outages with generator interconnection outages.

[7] *Id.*
[8] For example, see Southern California Edison 2020-2022 Wildfire Mitigation Plan, https://www.sce.com/sites/default/files/AEM/SCE%202020-2022%20Wildfire%20Mitigation%20Plan.pdf.

Q: WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE ANNUAL BUILD LIMITS DUKE IMPOSED ON SOLAR AND BATTERY RESOURCES IN ITS CPIRP MODELING?

A: Duke's arbitrary limits on solar and battery interconnection should be greatly increased if not eliminated. As explained below, these limits do not reflect reality, and there are many potential solutions to the interconnection challenges Duke claims in its attempt to justify these limits. These limits artificially constrain the contributions of solar and storage in the portfolios presented in Duke's CPIRP. In particular, this limits solar and storage from realizing their full potential to displace Duke's claimed need for new gas power plants to meet a need for energy and capacity.

Q: DOES DUKE'S CPIRP ACCURATELY PORTRAY THE IMPACT OF OUTAGES REQUIRED FOR GENERATOR INTERCONNECTION ON TOTAL TRANSMISSION OUTAGES?

A: No. Generator interconnection outages are a small share of total transmission outages. Duke accurately notes that transmission outages are required for many reasons other than generator interconnection, including "maintenance, NERC preventive maintenance requirements, asset management programs, NERC TPL-001 Standard Upgrade projects, new retail and wholesale delivery points, outage restoration."[9] Data provided in Duke's CPIRP shows that,

[9] Duke Proposed CPIRP, App'x L at 21.

even under a worst-case assumption that generator interconnection outages are purely additive to other types of transmission outages, and that small generators continue to comprise a significant share of interconnecting solar generators, interconnecting 1,800 MW of solar per year would require 150 outages. Duke claims that in this scenario generator interconnection outages would account for about 15% of the transmission line outages taken in a typical year,[10] but even this claim overstates the impact because Duke notes that **line** outages only comprise around 40% of total transmission outages. Given that transmission outages typically have an impact on operations regardless of whether they involve an outage of a line or other transmission equipment, a more accurate comparison is that interconnecting 1,800 MW of solar per year would comprise just 5.6-6.5% of **total** transmission outages in recent years, not just line outages. As shown in Table 1 above, Duke's modeling assumes that it could reach 1,800 MW of solar interconnections in 2032, after limiting solar interconnections to 1,350 MW in 2028 and 2029 and 1,575 MW in 2030 and 2031. Based on Duke's own figures, Duke's assumed limit of 1,350 MW of solar interconnections per year in 2028 and 2029 would only account for 4-5% of total transmission outages in recent years. When asked in discovery, Duke was unable to demonstrate that this number of outages would be unmanageable or harm reliability. Given that outages required for generator interconnection are planned well in advance, they

[10] *Id*.

are less disruptive than unplanned outages required for equipment outage restoration or other reasons. Moreover, as discussed below, there are many potential solutions for reducing the impact of generator interconnection outages.

Q: WHAT TYPES OF SOLUTIONS CAN BE USED TO ACCOMMODATE MORE GENERATOR INTERCONNECTIONS?

A: One solution is that outages required for generator interconnection can be combined with or timed to coincide with planned outages of the same transmission facilities taken for the other reasons discussed above. However, Duke does not appear to account for this opportunity to combine outages, instead writing that "Outages to accommodate interconnections of resources are additive to the line outages needed in a given year, which are scheduled to occur primarily in the spring and fall."[11]

For example, the significant reconductoring and rebuilding of transmission facilities that Duke is undertaking requires extended outages of those facilities. The Red Zone Expansion Plan (RZEP) transmission projects are concentrated in areas experiencing the most solar interconnections, so it should be possible to time the actual interconnection of new solar generators to occur while the transmission equipment is already on outage to complete those upgrades. Moreover, once planned transmission upgrades including the RZEP projects are complete, that should increase the ability to take generator interconnection

[11] Duke Proposed CPIRP, App'x L at 21.

outages because the transmission system will have greater capacity and redundancy and thus can better maintain reliable operations during outages.

As discussed later in my testimony, proactively-planned high-capacity transmission upgrades are far more efficient than incremental network upgrades identified through the reactive interconnection queue process. This not only reduces the cost of the upgrades, but also the time and complexity because a single proactively-planned upgrade can take the place of many smaller reactive network upgrades. As a result, following the recommendation made later in my testimony to move to proactive multi-value transmission planning will not only save ratepayers money, but will also address Duke's stated concerns about the time and complexity of interconnecting new generators.

Duke correctly notes that another potential solution to reduce the number of required outages for interconnecting a given MW quantity of new resources is to select larger generation projects. The outage calculations presented in Duke's CPIRP assume new solar resources average 67 MW,[12] which is below the arbitrary statutory 80 MW cap on solar PPA project size. Moreover, there is no such cap on the size of projects Duke can build. Nationally, 78% of solar capacity installed in 2022 was at projects in the 100-400 MW range, at least in part because installed costs for these larger projects are 35% lower than for projects

[12] Duke Proposed CPIRP, App'x L at 20. 2,289 MW divided by 34 projects equals an average of 67.32 MW/project.

in the 5-20 MW range.[13] Conservatively doubling Duke's assumed solar project size to 134 MW[14] under Duke's maximum cap of 1,800 MW of solar additions per year would halve solar's share of recent transmission outages from 6% to 3%, in addition to reducing the cost of solar.

Another solution is for new generators to share interconnections with other new or existing generators. If two new generators can be interconnected at the same time, that halves the number of required outages. If a new generator can interconnect on the radial direct interconnection facility of an existing generator, that can reduce or eliminate the need to take an outage on the networked transmission system.

Another potential solution is a temporary "shoo-fly" line that keeps a critical line in service or interconnects a resource while longer-duration upgrades are completed. Solar generators could also be interconnected under a provisional service agreement or as an energy-only resource ahead of the completion of network upgrades that are needed for full delivery of its output. This would allow Duke to wait for an opportune time for the transmission line to be taken out of service, ideally combined with other needed outages, to complete the interconnection or upgrade.

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[13] Berkeley Lab, *Utility-Scale Solar*, https://emp.lbl.gov/utility-scale-solar, tab "CapEx by Size" (last visited May 27, 2024).

[14] This could be achieved, for example, by purchasing 45% of solar capacity from third-party solar projects that are less than 80 MW each, as required by law, and obtaining the remaining 55% of solar capacity from Duke-owned installations that average 180 MW each.

Q: WHAT IS YOUR OVERALL REACTION TO DUKE'S CLAIM THAT OUTAGE COORDINATION IMPOSES A HARD LIMIT ON THE INTERCONNECTION OF NEW RESOURCES?

A: It is simply not credible for Duke to claim that it cannot accommodate a temporary 3-6% increase in transmission outages as it brings new resources online. When asked about this in discovery, Duke was unable to provide support for its claims.[15]

Q: HOW CAN PROVISIONAL SERVICE EXPEDITE INTERCONNECTION?

A: FERC Order 845 requires transmission service providers like Duke to allow generators to interconnect prior to completion of full interconnection studies and identified network upgrades, if studies indicate the generator can do so reliably.[16] Duke has filed a process for FERC-jurisdictional interconnections to use provisional service, but does not currently offer an equivalent provision for state-jurisdictional interconnections, which the Commission could require. Duke has proposed terms for provisional service that would allow both FERC- and state-jurisdictional resources to interconnect in this way.[17]

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[15] See Duke's response to SACE DRs 32-4, attached as **Exhibit MG-2**, and 31-1, attached as **Exhibit MG-3**.

[16] Reform of Generator Interconnection Procedures and Agreements, 163 FERC ¶ 61,043, Order No. 845 at P 424 (Apr. 19, 2018), https://www.ferc.gov/sites/default/files/2020-06/Order-845.pdf.

[17] Duke Energy, *DEC, DEP, & DEF Provisional Service Filings Update* (Apr. 19, 2024), https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/4.19.24_DEC_DEF_DEP_Provisional_Service_Filings_Update_Meeting_Presentation.pdf.

Q: HOW CAN ENERGY RESOURCE INTERCONNECTION SERVICE (ERIS) BE USED INSTEAD OF NETWORK RESOURCE INTERCONNECTION SERVICE (NRIS) TO EXPEDITE INTERCONNECTION?

A: Another solution is ERIS, which typically allows a generator to interconnect with less complex interconnection studies and fewer interconnection upgrades in exchange for some risk that the generator's output will be curtailed due to transmission constraints. ERIS contrasts with NRIS, which requires more extensive study and upgrades and is typically used to ensure capacity resources can deliver their full output at times of peak demand. The U.S. Department of Energy's Interconnection Innovation e-Xchange (i2X) program, of which Duke is an inaugural partner, just released a roadmap on how to speed up interconnection. The use of ERIS and generation redispatch to avoid a need for upgrades feature prominently in those recommendations.[18]

ERIS can be particularly attractive for solar resources on Duke's system, given the low capacity accreditation Duke assigns to them.[19] Curtailment risk should not reduce solar's capacity value because Duke's capacity accreditation is based on loss of load risk in winter, when the transmission system's capacity is

[18] U.S. Dep't of Energy, *Transmission Interconnection Roadmap: Transforming Bulk Transmission Interconnection by 2035* at 52 (Apr. 2024), https://www.energy.gov/sites/default/files/2024-04/i2X%20Transmission%20Interconnection%20Roadmap.pdf.

[19] Astrapé Consulting, *Duke Energy Carolinas and Duke Energy Progress Effective Load Carrying Capability (ELCC) Study* (Apr. 25, 2022), https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/attachment-02-2022-elcc-study.pdf?rev=1d9bbe26628645de8762bec47630df89.

much greater due to lower ambient temperatures and the output of other solar resources using those transmission lines is much lower than it is during summer periods.

Q: DOES DUKE RAISE CONCERNS ABOUT THE USE OF ERIS?

A: In a recent presentation arguing against studying a transmission planning scenario that involves widespread use of ERIS, Duke claimed that "solar developers have stated that they need the certainty of NRIS for project financing purposes."[20] However, many solar developers would likely assign more value to the faster interconnection and greater interconnection cost certainty that typically comes with ERIS service, relative to any increased risk of curtailment under ERIS relative to NRIS. In fact, solar developers have strongly advocated for ERIS service.[21] Moreover, once interconnected, ERIS resources can convert to NRIS if they complete additional studies and any required upgrades.

Potential curtailment is typically a small risk for ERIS resources. Interconnection studies provide snapshots of a generator's ability to deliver its power under worst-case transmission system conditions, typically assuming a perfect storm of peak demand coinciding with a large generator and/or transmission asset being offline due to contingency events. Contingency events

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[20] Duke Energy, Presentation: 2024 Multi-Value Strategic Transmission Study at slide 7 (April 2024), attached as **Exhibit MG-4**.

[21] Comments of Carolinas Clean Energy Business Association, *In the Matter of: Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, 2024 Solar Procurement Pursuant to Initial Carbon Plan*, Docket Nos. E-2, Sub 1340 and E-7, Sub 1310 (N.C.U.C. May 10, 2024), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=20797413-6a60-49cd-9412-b7608904df3e.

are rare and typically have a short duration, particularly generator contingencies, as NERC's BAL-002 Standard requires contingency reserves to replace generation experiencing a forced outage within 15 minutes. As a result, a resource that would have its output curtailed under those worst-case conditions is typically able to deliver its output in nearly all hours in a year. As a result, ERIS generators are able to secure the financing required to proceed to construction. For example, all generators in ERCOT effectively receive ERIS service, and as noted above ERCOT has been able to interconnect more than 10,000 MW per year. Duke can also help manage any curtailment risk. Solar developers signing power purchase agreements with Duke already contractually agree on how curtailment risk will be allocated between them, and contractual issues related to curtailment are not an issue for Duke-owned solar resources. ERIS resources do not pose a reliability concern, as Duke controls generation dispatch for all resources on its system and can curtail ERIS resources as needed to ensure transmission system reliability.

Duke can also make ERIS more attractive by revising the methods it uses in ERIS interconnection studies. For example, in ERIS studies Duke conservatively assumes that "Transmission capacity is available as long as no transmission element is overloaded under N-1 transmission conditions. The thermal evaluation will only consider the DISIS Study under N-1 transmission contingencies to determine the availability of transmission capacity."[22] As noted above, N-1 transmission contingencies coinciding with the peak conditions studied in an interconnection study are extremely rare, accounting for an extremely small share of hours in a year. Moreover, typical utility practice is to allow transmission lines and other equipment to exceed their normal thermal ratings and operate at higher emergency ratings in the minutes following a system contingency, as doing so occasionally for short periods of time has minimal impact on the life of the transmission asset. As a result, studying resources under this worst-case snapshot does not reflect their curtailment risk in virtually all hours in a year. Instead, Duke should study ERIS resources under normal system conditions, and any risk of curtailment in the unlikely event that a large system contingency occurs during peak demand periods would be manageable.

Q: CAN DUKE USE OTHER TYPES OF TRANSMISSION SERVICE TO EXPEDITE INTERCONNECTION?

A: Yes. One option is Surplus Service Interconnection, which could be used to interconnect renewable or battery resources at existing Duke generator sites with little to no need for upgrades. This is a FERC Order 845 tariff mechanism that allows for the sharing of an existing interconnection subject to mutual agreement with the existing generator. For example, an existing fossil generator

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[22] Duke Energy Progress, *2022 Definitive Interconnection System Impact Study Phase 1 Report* at 79 (Nov. 23, 2022), https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022-11-23_DEP_2022_DISIS_Phase_1_Study_Report.pdf.

which seldom operates can share its interconnection with a renewable and/or storage generator that primarily produces in different hours.

Q: CAN DUKE EXPEDITE INTERCONNECTION BY MAKING OTHER ASSUMPTIONS USED IN ITS INTERCONNECTION STUDIES MORE REALISTIC?

A: Yes. As discussed above, interconnection studies are typically based on worst-case assumptions, which can make sense for capacity resources that must deliver on-peak or resources that cannot quickly change their output. However, these assumptions do not make sense for wind or solar resources that receive limited capacity value, or for wind, solar, and storage resources that can adjust their output within seconds in response to a system contingency. As discussed below, the ability of inverter-based resources like wind, solar, and battery storage to quickly regulate their output and voltage can make it easier to interconnect these resources without triggering thermal overload or stability concerns, and this should be reflected in interconnection study assumptions. Interconnection studies should also reflect how resources are actually dispatched, instead of often unreasonable assumptions about resources' output levels during the snapshots evaluated in interconnection studies. For example, economic dispatch ensures that batteries never charge at system peak demand or discharge when local transmission constraints would limit their output. In addition, study assumptions should reflect typical utility practice of allowing transmission lines and other equipment to exceed their normal thermal ratings and operate at higher emergency ratings in the minutes following a system contingency, as discussed above. This would greatly reduce interconnection challenges as the vast majority of the upgrades identified in recent Duke interconnection studies are thermal overloads and not stability problems. For example, of the $470 million in network upgrades identified in the DEP solar and solar plus storage Resource Solicitation Cluster (RSC) Phase 1 study, 75% of upgrades were due to thermal overloads and zero due to short circuit or stability concerns.[23]

Q: ARE THE ANNUAL INTERCONNECTION LIMITS DUKE ASSUMES FOR BATTERIES IN ITS CPIRP JUSTIFIED?

A: No. As indicated in Table 1, Duke limits battery additions to 200 MW in 2027, 500 MW each in 2028 and 2029, and 1,000 MW in 2030 and beyond. Duke claims these limits are needed to account for "cumulative effect on interconnection construction volumes, impact to forecast global stationary battery storage equipment and construction services markets, potential for further storage technology development and price declines over the longer-term, and availability of locations on the transmission system requiring relatively low upgrades to facilitate new firm interconnection."[24] The claims related to battery prices and global supply chain issues are addressed below.

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[23] Duke Energy Progress, *2023 Resource Solicitation Cluster Phase 1 Report* (Apr. 26, 2024), https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2023_DEP_Resource_Solicitation_Cluster_(Phase_1)_Study_Report.pdf.

[24] Duke Proposed CPIRP, Supp. Planning Analysis at 26.

Duke's claimed interconnection constraints do not reflect the ability to quickly install batteries at optimal points on the grid due to their modularity and flexibility. Due to batteries' flexibility, under economic dispatch they will always be operated so that they avoid causing overloads that trigger a need for grid upgrades. Batteries can quickly and accurately inject or withdraw power or regulate voltage, allowing them to not only avoid triggering overload or stability concerns, but even helping to address those concerns. Batteries are small and modular and thus can be deployed at points on the grid where they can be easily interconnected, or even where those services are most needed. Duke itself has noted that batteries can easily be deployed at existing or retired generator sites where they can typically be interconnected without a need for grid upgrades.[25]

However, Duke overstates the challenges of interconnecting storage when it writes that "Transmission system evaluations will need to consider when additional load is placed on the system with the demand of energy from energy storage systems such as charging batteries…"[26] This assertion misunderstands that economic dispatch already ensures batteries will never charge during peak demand periods. In fact, pursuant to a requirement in FERC Order 2023, Duke now allows storage interconnection customers to specify charging and discharging behavior,[27] reflecting that interconnection upgrades are typically not

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[25] Duke Proposed CPIRP, App'x L at 27.

[26] *Id.* at 6.

[27] Improvements to Generator Interconnection Procedures and Agreements, 184 FERC ¶ 61,054, Order 2023 at P 1509 (July 2023), https://www.ferc.gov/media/e-1-order-2023-rm22-14-000.

needed to accommodate charging because batteries can be dispatched so that they do not charge during periods of peak transmission system usage.

Q: ARE DUKE'S OTHER CLAIMS ABOUT "INCREASINGLY COMPLEX INTERCONNECTIONS" A MAJOR IMPEDIMENT FOR SOLAR INTERCONNECTIONS?

A: No. Duke argues that solar developers have used up available land and interconnection capacity near existing transmission lines, forcing new generators to use longer tie lines to reach the transmission system. Tie lines and other direct interconnection facilities are the responsibility of the interconnecting generator and not Duke, so it is unclear why this trend would "further consume available resources and limit the maximum achievable annual interconnections" as Duke claims.[28] The length of a tie line also does not affect the equipment required at the point of interconnection or the magnitude of required network upgrades.

Q: WHAT OTHER CONCERNS DOES DUKE RAISE ABOUT THE ABILITY TO INTERCONNECT SOLAR AND STORAGE RESOURCES?

A: Duke also points to planned resources that in the past have failed to interconnect due to "the ability to obtain materials in a timely manner due to global supply chain disruptions and other unforeseen developer realizations such as material and labor cost inflation occurring between bid acceptance and construction phases."[29] As noted above, Duke also expresses concerns about

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[28] Duke Proposed CPIRP, App'x L at 20.

[29] *Id.* at 23.

supply chain issues affecting prices for batteries. These concerns are out of date and do not apply to new resources that Duke would procure later this decade pursuant to the CPIRP, as supply chain issues that affected the delivery of equipment for all types of generators have already largely subsided. For example, industry data reveal prices for solar modules have fallen by around half since mid-2023, from around \$0.27/Watt in June-July 2023 to \$0.14/Watt in March 2024,[30] reflecting the resolution of supply chain constraints. Battery cell prices have also fallen by 50-60% over the last year, with continued declines expected for the foreseeable future as supply growth outpaces demand.[31] It remains to be seen how recently announced tariffs on Chinese goods will affect the cost of solar and storage resources. In the past, industry has been able to adapt to tariff changes by sourcing from other countries, and federal incentives are driving a resurgence of domestic manufacturing. Regardless, developers can factor these tariffs into their bids, so they will not cause unexpected price increases like those that have delayed projects in the past.

As noted above, Duke also cites the "impact to forecast global stationary battery storage equipment and construction services markets" as a reason to limit annual battery installations. In reality global battery prices are mostly

[30] PVXchange, *Price Index – February 2024*, https://www.pvxchange.com/Price-Index (last accessed Mar. 2024), with the June/July 2023 cost converted to dollars at the conversion rate of 1.09 dollars/euro on June 30, 2023, and the March 2024 cost converted at the current exchange rate of 1.08 dollars/euro.

[31] John Weaver, *Battery prices collapsing, grid-tied energy storage expanding*, PV Magazine (March 2024) https://pv-magazine-usa.com/2024/03/06/battery-prices-collapsing-grid-tied-energy-storage-expanding/.

determined by supply and demand for battery cells, which are primarily used in electric vehicles and applications other than grid-tied storage. Even for equipment and services that are exclusively used in the grid-tied storage market and not for other battery applications, Duke's demand would comprise a trivial share of total global demand, with Duke estimating its share of the global grid-tied battery market at around 1%.[32] Duke's share of the total global battery market would be a small fraction of that, given that grid-tied batteries are expected to continue to account a very small share of total demand for lithium ion battery cells.[33] Battery modules account for most of the total cost of grid-tied battery storage, so battery costs heavily determine the total cost of battery storage.[34] As a result, it is inconceivable that Duke's demand for batteries in any year would have a noticeable impact on price or availability in these global markets.

Duke's argument that it should limit battery deployments to take advantage of future cost reductions also does not make sense for several reasons. First, economic generator capacity expansion models like those used by Duke for the CPIRP are fully capable of modeling the optimal timing for deploying resources given expected cost declines, and imposing annual

[32] Duke's response to PS DR 40-1(a), attached as **Exhibit MG-5**.

[33] Deshwal et al., *Economic Analysis of Lithium Ion Battery Recycling in India*, Wireless Personal Communications, 124(2). (Jun. 2022) https://www.researchgate.net/figure/Lithium-ion-battery-global-market-size-GWh-Source-Bloomberg-New-Energy-Finance-BNEF_fig4_357887808.

[34] NREL, *Utility-Scale Battery Storage*, https://atb.nrel.gov/electricity/2023/utility-scale_battery_storage (last visited May 27, 2024).

installation limits only forces the model to choose a sub-optimal deployment timeline. Second, if battery resources are the lowest-cost resource for meeting a capacity need in a given year, postponing their deployment only increases costs for ratepayers by forcing the model to select suboptimal capacity resources in that year. Battery build limits are particularly nonsensical given that Duke is proposing to build a large amount of gas to meet a claimed near-term capacity need. As explained above, batteries are highly modular and can be deployed quickly without triggering lengthy network upgrades.

Q: CAN BATTERIES EXPEDITE THE INTERCONNECTION OF NEW RENEWABLE RESOURCES IN THE NEAR-TERM?

A: Yes. Batteries are highly effective at facilitating the interconnection of renewable resources, including by absorbing renewable output that would have been curtailed due to transmission system overloads. Batteries can be added to a renewable deployment to make a hybrid resource, or installed as a stand-alone resource nearby or at other optimal points on the grid. As noted above, due to batteries' speed of dispatch, the ability of their power electronics to regulate voltage and reactive power and address local stability concerns, and their ability to be quickly deployed at points on the grid where they are needed, battery storage can be an effective alternative to transmission upgrades, particularly upgrade needs triggered by contingency conditions.[35] Batteries also serve as

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[35] *See* Brent Oberlin, *Storage as a Transmission Only Asset* at 11-15 (May 2022), https://www.iso-ne.com/static-

capacity resources, directly reducing the need for the Company's proposed gas capacity additions.

Q: WHAT ARE GRID-ENHANCING TECHNOLOGIES, AND HOW CAN THEY EXPEDITE THE INTERCONNECTION OF NEW RESOURCES?

A: Dynamic line ratings, power flow control devices, topology optimization techniques, and similar grid-enhancing technologies[36] (GETs) can be deployed quickly, typically within a matter of months,[37] so they can play an important role in alleviating near-term transmission constraints so new resources or loads can be interconnected while longer-term transmission upgrades are implemented. Recognizing their ability to quickly and cost-effectively alleviate transmission constraints, the just-released FERC Order 1920[38] places a significant emphasis on the use of these technologies, as did FERC Order 2023. GETs have low costs so they provide large net benefits.

Analysis by the Brattle Group found that 2,670 MW of additional wind capacity could be added in SPP by adopting dynamic line ratings, power flow

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assets/documents/2022/05/a7_storage_as_a_transmission_only_asset.pdf; and Quanta Technology, *Storage as Transmission Asset Market Study* (January 2023), https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf.

[36] Rob Gramlich, *Bringing the Grid to Life: White Paper on the Benefits to Customers of Transmission Management Technologies* (Mar. 2018), https://watttransmission.files.wordpress.com/2018/03/watt-living-grid-white-paper.pdf.

[37] *See* Idaho Nat'l Lab., *A Guide to Case Studies of Grid Enhancing Technologies* at 11, 26 (Oct. 2022), https://inl.gov/content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf.

[38] FERC Order 1920, at PP 1163-1247 (May 13, 2024), https://www.ferc.gov/media/e1-rm21-17-000.

control devices, and topology optimization, more than doubling the amount of wind capacity that can be added while keeping curtailment at an acceptable level.[39] Brattle found a one-time investment of $85 million in these low-cost transmission technologies would yield annual production cost savings of $175 million—a more than two-to-one ratepayer benefit.

Dynamic line ratings allow more power to safely flow on transmission lines by accounting for how ambient weather conditions affect the thermal limits of those lines. Transmission line ratings are typically based on worst case weather assumptions: hot weather with full sun and no wind cooling the line. Dynamic line rating devices measure the actual thermal limit of transmission lines, which under most weather conditions are much higher than the limits based on those worst-case assumptions. Due to the large potential benefits, FERC recently initiated an inquiry examining whether dynamic ratings should be required.[40]

Power flow control devices, also known as Flexible Alternating Current Transmission Systems devices, can also be deployed quickly to increase interconnection capacity on the existing transmission system. These are power electronics-based devices used to adjust the power transfer capabilities of the system and improve stability or controllability of the system under critical

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[39] Bruce Tsuchida, Stephanie Ross, Adam Bigelow, *Unlocking the Queue with Grid-Enhancing Technologies*, at 8 (February 2021), https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

[40] FERC, *FERC Opens Inquiry on Use of Dynamic Line Ratings to Promote Grid Efficiency*, (February 2022), https://www.ferc.gov/news-events/news/ferc-opens-inquiry-use-dynamic-line-ratings-promote-grid-efficiency.

conditions. Topology optimization plays a similar role by taking specific transmission lines out of service to redirect power flow away from congested transmission elements and onto more optimal paths. Both of these solutions can play an important role in alleviating constraints during transmission contingency events.

Q: WHAT ARGUMENT DOES DUKE OFFER FOR NOT DEPLOYING GRID-ENHANCING TECHNOLOGIES?

A: Duke's CPIRP argues that: "Over-reliance on GETs can lead to circumstances where operators cannot successfully assess potential risks, hazards, or system events that might occur."[41]

Q: IN REALITY, HOW DO GRID-ENHANCING TECHNOLOGIES AFFECT OPERATIONAL COMPLEXITY?

A: They reduce it. Dynamic line ratings give operators precise information about a line's transmission capacity instead of relying on engineering estimates. Power flow control devices and topology optimization provide operators with more control of the flow of power on the AC transmission system, mitigating loop flow and preventing inadvertent overloads of transmission equipment.

Duke's stated concerns appear more relevant to remedial action schemes, which are entirely different from GETs. Remedial action schemes automatically take actions to change the flow of power on the transmission system, like tripping

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[41] Duke Proposed CPIRP, App'x L, at 15.

generation or load, under certain conditions such as contingency events.[42] These are often used as interim solutions, and Duke is correct that they can increase operational complexity. But to be clear, remedial action schemes are not GETs, and we are not advocating for their use.

Q: BASED ON THE ABOVE, WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A: Duke's arbitrary limits on solar and battery interconnection should be greatly increased if not eliminated. These limits artificially constrain the deployment of cost-effective renewable and storage resources, increasing costs for ratepayers. The Commission should also direct Duke to take the steps outlined above to expedite the interconnection of new resources:

- Maximize use of Provisional Interconnection Service, Energy Resource Interconnection Service, and Surplus Interconnection Service, including revising the study methods and processes for those types of service to make them more workable for developers;
- Revise interconnection study assumptions to reflect actual generation and transmission operating practices;
- Assess how strategically-sited batteries can address transmission needs and facilitate the interconnection of other new resources; and

[42] NERC, *"Remedial Action Scheme" Definition Development: Background and Frequently Asked Questions: Project 2010-05.2 – Special Protection Systems* (Jun. 2014), https://www.nerc.com/pa/Stand/Prjct201005_2SpclPrtctnSstmPhs2/FAQ_RAS_Definition_0604_final.pdf.

- Require Duke to justify why it did not deploy one or more GETs as a near-term solution for an identified transmission constraint.

III. <u>Duke should reduce or eliminate its assumed wind and solar generic transmission network upgrade proxy costs</u>

Q: FOR THE ECONOMIC MODELING FOR THE CPIRP, WHAT DOES DUKE ASSUME FOR THE COST TO INTERCONNECT NEW RENEWABLE RESOURCES?

A: For its DEP footprint, Duke assumes that generic transmission network upgrade proxy costs are [BEGIN CONFIDENTIAL] [redacted][43] [END CONFIDENTIAL] As explained below, Duke's assumed interconnection costs do not account for the benefits of that transmission, or a number of factors that should reduce these costs. As a result, I conservatively recommend that Duke use the proposed DEP costs in place of the higher costs assumed for DEC, though arguably these costs should be even lower or eliminated entirely.

Q: HOW DO DUKE'S ASSUMED WIND AND SOLAR UPGRADE COSTS AFFECT THE GENERATION PLAN DEVELOPED IN DUKE'S CPIRP?

[43] PSDR 1-7, CONFIDENTIAL_Updated with Phase II Study Results - Trans Cost Assumptions DEC and DEP 2023v1_SPA, attached as **Exhibit MG-6**.

A: The excessive interconnection costs bias the CPIRP's generation economic optimization analysis against wind and solar resources, as the assumed costs for wind and solar resources are significantly greater than Duke's assumed costs for interconnecting conventional generators. This impact is likely quite large, as Duke's assumed upgrade costs for DEC account for 11% of the capital cost of solar resources and 8% of the cost of wind resources.

Q: WHY ARE THE GENERIC TRANSMISSION NETWORK UPGRADE COSTS DUKE ASSUMED FOR DEC RENEWABLE GENERATORS IN THE CPIRP EXCESSIVE?

A: The network upgrade costs assumed for DEC solar and wind resources in Duke's CPIRP are likely to be significantly too high for several reasons. First, these transmission network upgrades are likely to provide benefits that are many times greater than their cost, effectively giving them a negative net cost to ratepayers. The Direct Testimony of Mr. Roberts notes that the benefit-cost ratios for each of the RZEP 1.0 transmission projects, which were designed to interconnect renewable resources, ranged from over 5:1 to nearly 23:1 per project, with an average of around \$15 in benefits for every \$1 invested for the total portfolio of projects. As noted below, this calculation is based solely on Duke's calculation of the customer reliability benefits of those upgrades and not the other benefits of transmission expansion, making that estimate conservative. Given that Mr. Roberts concludes that the customer reliability benefits of the RZEP network upgrades to interconnect new renewable resources "outweigh the costs by a material margin," it is likely that future network upgrades to interconnect the CPIRP renewable resources will also provide benefits that are greater than their cost.[44]

Mr. Roberts' Supplemental Direct testimony confirms that each of the RZEP 2.0 projects also provide benefits that are 4-34 times greater than their cost. However, I should note that his testimony understates the net benefits of the total package of RZEP 2.0 projects by claiming the average benefit-cost ratio is 13:1,[45] when the total package provides benefits that are actually 17 times greater than their cost. It appears that Mr. Roberts is referring to the 13.8:1 benefit-cost ratio of the RZEP 2.0 projects before the inclusion of the Lee-Milburnie 230 kiloVolt (kV) project, which increases the benefit-cost ratio for the RZEP 2.0 projects to 17:1.

Second, the reliability benefits Duke quantified to calculate the benefit-cost ratio for the RZEP projects capture only a small share of the total benefits of transmission, as I explain in more detail below. As a result, the true benefit-cost ratio for these upgrades is likely significantly higher than Duke's already large estimate. Moreover, if Duke uses proactively-planned multi-value transmission upgrades to interconnect the CPIRP renewable resources, as I recommend later in my testimony, it will be able to design those lines to maximize reliability, economic, and other transmission benefits while minimizing cost, offering even

[44] Roberts Direct, at 29.

[45] Roberts' Supplemental Direct, at 9:1.

larger net benefits for ratepayers. Given their large net benefits, it is inappropriate for Duke's CPIRP to characterize these transmission upgrades as costs associated with renewable generators—if anything these upgrades should be viewed as a net benefit to customers.

Third, Mr. Roberts notes that the generic network upgrade costs assumed in the CPIRP were derived from upgrades identified in the 2022 Definitive Interconnection System Impact Study (DISIS). In response to discovery questions, Duke confirmed that [BEGIN CONFIDENTIAL] [redacted].[46] [END CONFIDENTIAL] The vast majority of renewable projects that applied to interconnect during the 2022 DISIS have already dropped out of the queue due to excessive network upgrade costs. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] This is confirmed by data for other regions, as documented below. Similarly, the assumed wind upgrade cost is based on a few speculative

[46] Duke's response to SACE, et al. Data Request 33-2, attached as **Exhibit MG-7**, confirming that Duke's response to Sierra Club Data Request 2-1.a from the IRP proceeding in South Carolina would be the same in this proceeding.

projects that do not appear to be representative of wind projects that are likely to be built in the future.

Finally, transmission investment offers significant economies of scale, with higher-voltage lines offering a much lower cost per interconnected MW than lower-voltage lines. Therefore, it is likely that the higher-voltage upgrades that will be planned to integrate future renewable resources will be more cost-effective than the 115-kV and 230-kV DISIS upgrades Mr. Roberts used as the basis for the generic network upgrade costs.

Q: HOW DO THE GENERIC TRANSMISSION NETWORK UPGRADE COSTS DUKE ASSUMED FOR RENEWABLE GENERATORS IN THE CPIRP COMPARE TO COSTS IN OTHER REGIONS?

A: As noted above, Duke's assumed cost for solar and wind network upgrades in DEC is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Lawrence Berkeley National Laboratories' recent analyses of wind and solar interconnection costs in other regions find that while proposed projects may have costs in this range, interconnection costs for the subset of projects that move forward to completion are much lower. For example, they find that projects that move forward to completion in MISO "averaged $102/kW for complete projects from 2019 through 2021,"[47] while in PJM they found that projects completed

[47] Berkeley Lab, *Interconnection Cost Analysis in the Midcontinent Independent System Operator (MISO) Territory* at 1 (Oct. 2022), https://live-

between 2020 and 2022 averaged $84/kW for interconnection costs.[48] [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q: YOU MENTIONED THAT TRANSMISSION EXHIBITS ECONOMIES OF SCALE. CAN YOU QUANTIFY THE SAVINGS ASSOCIATED WITH BUILDING HIGHER-CAPACITY TRANSMISSION?

A: Yes. MISO's annual estimate of transmission costs provides data illustrating the large economies of scale for higher-voltage and double-circuit transmission, which are used to calculate the results shown in Table 3 below. [49] On a $/MW-mile basis, which reflects the average cost of transmission to deliver one MW one mile, double-circuit 230-kV transmission is 36% less costly than double-circuit 115-kV, and 500-kV is 60% less costly than double-circuit 115-kV transmission. This indicates that future transmission expansion to accommodate

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etabiblio.pantheonsite.io/sites/default/files/berkeley_lab_2022.10.06-_miso_interconnection_costs.pdf.

[48] Berkeley Lab, *Interconnection Cost Analysis in the PJM Territory* at 5 (Jan. 2023), https://live-etabiblio.pantheonsite.io/sites/default/files/berkeley_lab_2023.1.12-_pjm_interconnection_costs.pdf.

[49] Midcontinent Indep. Sys. Operator, *Transmission Cost Estimation Guide for MTEP24* (Jan. 2024 draft), https://cdn.misoenergy.org/20240131%20PSC%20Item%2005%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24%20-%20Redline631529.pdf (Table 1 was prepared using the reported Power rating (MVA) capacity data in Table 3.1.5 on page 43 and the estimated costs for Arkansas reported in Tables 4.1.1 and 4.1.2 on pages 47–49. Costs for Arkansas were used as they are in the middle of the range of MISO's cost estimates by state, and are likely to be more representative of costs in the Southeast. The Power rating (MVA) capacity data for the Double Circuit are twice the capacity for the Single Circuit.).

larger renewable resource additions will likely be less costly than the lower-voltage transmission expansion Duke has used to date, particularly if Duke plans that future transmission using the proactive multi-value planning approaches I advocate later in my testimony.

Table 3: Economies of scale for higher-voltage transmission lines

	Voltage (kV)	69	115	138	161	230	345	500	765
Single Circuit	$M/mile	$1.7	$1.9	$2.0	$2.1	$2.2	$3.5	$4.4	$5.5
	MW or MVA	140	329	394	460	657	1792	2598	6625
	$/MW-mile	**$12,143**	**$5,775**	**$5,076**	**$4,565**	**$3,349**	**$1,953**	**$1,694**	**$830**
Double Circuit	$M/mile	2.5	2.8	2.9	3	3.6	5.8	NA	NA
	MW or MVA	280	658	788	920	1314	3584	NA	NA
	$/MW-mile	**$8,929**	**$4,255**	**$3,680**	**$3,261**	**$2,740**	**$1,618**	**NA**	**NA**

Q: EARLIER IN THIS SECTION, YOU MENTIONED THAT TRANSMISSION PROVIDES MANY BENEFITS IN ADDITION TO THE RELIABILITY BENEFIT THAT DUKE QUANTIFIED FOR THE RZEP PROJECTS. WHAT ARE THESE BENEFITS?

A: Duke's cost-benefit evaluation of the RZEP projects only accounts for how transmission projects reduce customer outages, even though transmission provides many additional benefits. For example, the just-released FERC Order 1920 will require transmission planners to account for the following seven categories of benefits provided by transmission,[50] while Duke's method just accounts for parts of categories 1 and 2:[51]

(1) avoided or deferred reliability transmission facilities and aging infrastructure replacement;

(2) either reduced loss of load probability or reduced planning reserve margin;

(3) production cost savings;

(4) reduced transmission energy losses;

(5) reduced congestion due to transmission outages;

(6) mitigation of extreme weather events and unexpected system conditions; and

(7) capacity cost benefits from reduced peak energy losses.

As I explain in the next section, these are the types of benefits that should be accounted for in multi-value transmission planning.

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[50] FERC Order No. 1920 ¶¶ 740-822.

[51] *See* Roberts Supplemental Direct, at 8.

Q: DO TRANSMISSION PLANNERS IN OTHER REGIONS ACCOUNT FOR TRANSMISSION BENEFITS OTHER THAN REDUCED CUSTOMER OUTAGES?

A: Yes. I co-authored a report providing examples of how transmission planners in other regions have accounted for those benefits.[52] Duke's transmission benefit-cost analysis is highly unusual in that it does not account for how transmission upgrades provide production cost savings by reducing transmission losses and allowing lower-cost generation to displace higher-cost resources. Production cost savings are typically one of the primary benefits transmission planners account for when evaluating benefit-cost ratios for transmission projects. For example, production cost savings account for about half of the benefits the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP) have found for their recent transmission expansions.[53] As a result, Duke's analysis significantly understates transmission's benefits.

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[52] Pfeifenberger, et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, Brattle Grp. & Grid Strategies LLC, Appendix D (Oct. 2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.

[53] *See* Midcontinent Indep. Sys. Operator, *MTEP17 MVP Triennial Review–A 2017 Review of the Public Policy, Economic, & Qualitative Benefits of the Multi-Value Project Portfolio* at e.g., 4-6 (Sept. 2017), https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf.; Sw. Power Pool, *The Value of Transmission – A Report by Southwest Power Pool* at e.g., 5 (Jan. 26, 2016), https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf; *see also* Sw. Power Pool, *The Value of Transmission – A 2021 Study and Report by Southwest Power Pool* (Mar. 31, 2022), https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf.

Q: HOW DOES THE FAILURE TO ACCOUNT FOR OTHER BENEFITS OF TRANSMISSION AFFECT DUKE'S ASSUMED GENERIC UPGRADE COSTS?

A: The large net benefits of transmission that interconnects renewables also confirm that the "upgrade costs" Duke assigns to interconnecting wind and solar generators should be viewed as net benefits. Because the true net benefits of these upgrades are even larger than Duke's already large estimate, this provides even further reason not to treat these upgrades as a net cost associated with renewable generators in the economic optimization analysis Duke uses in its CPIRP. At minimum, Duke should use the generic upgrade costs it assumed for DEP in place of the higher costs it assumed for DEC.

IV. <u>Duke should expeditiously use proactive multi-value transmission planning to build needed grid upgrades</u>

Q: DO YOU RECOMMEND THAT THE COMMISSION APPROVE THE RZEP 2.0 PROJECTS?

A: Yes. As noted in the preceding section, the benefit-cost ratio for the RZEP 2.0 lines is 17:0 based on reliability benefits alone, and would be much higher if transmission's other benefits were accounted for. Mr. Roberts indicates that the Lee-Milburnie 230 kV rebuild project adds 1,600 MW of interconnection capacity in eastern North Carolina, which will help interconnect proposed solar projects and also potentially wind development in that area. As a result, the Commission should approve the RZEP 2.0 investments.

Q: IS ADDITIONAL TRANSMISSION INVESTMENT NEEDED?

A: Yes. The RZEP 2.0 projects are necessary but not sufficient for meeting the needs of North Carolina ratepayers. As documented below, RZEP 2.0 only meets about 11% of the transmission need identified through Duke's 2023 Public Policy Study that would be required to interconnect 12.5 GW of clean resources to meet carbon reduction requirements. Specifically, 2023 Public Policy Study found accommodating 12.5 GW of resources would overload 1,100 miles of existing circuits, even with the RZEP 1.0 projects in place. RZEP 2.0, including the Lee-Milburnie 230 kV rebuild, provides 124 circuit miles towards addressing that need, so RZEP 2.0 accounts for only 11% of the circuit miles that need to be upgraded. The RZEP 1.0 projects involved upgrading 201 circuit miles, for a combined 325 circuit miles between RZEP 1.0 and 2.0. The 1,100 miles of additional transmission upgrades needed to interconnect the total 12.5 GW of new resources is thus more than five times greater than what has been approved so far with RZEP 1.0. As a result, there is an urgent need for further transmission expansion, including higher-voltage transmission, greenfield projects, and expanded transmission ties with neighbors, all of which can be most efficiently planned with proactive multi-value transmission planning.

Duke's load growth projections, if accurate, further increase the need for transmission beyond what was found in 2023 Public Policy study and the 2022 Carbon Plan, which were based on old load growth assumptions. This increase includes the need for transmission to interconnect new loads and accommodate higher demand, as well as interconnecting the generation needed to serve those loads and meet carbon reduction requirements.

Q: TO MEET THAT NEED, WHAT TYPE OF TRANSMISSION PLANNING SHOULD DUKE CONDUCT?

A: The Commission should require Duke to develop a proactive multi-value synchronized generation and transmission plan, as other utilities and regions have found this to be the most effective and beneficial method for planning transmission. As I explain below, the Carolinas Transmission Planning Collaborative's (CTPC's) Multi-Value Strategic Transmission (MVST) planning appears to contain elements of that approach, but Commission oversight is required to ensure that Duke uses that process to plan the high-capacity transmission expansion that will be needed to minimize costs for North Carolina ratepayers.

Q: WHAT DO YOU MEAN BY "PROACTIVE MULTI-VALUE" TRANSMISSION PLANNING?

A: "Multi-value" refers to transmission planning that attempts to identify transmission upgrades that maximize net benefits across the many categories of transmission benefits I discussed in the previous section, in contrast to transmission planning that is only focused on realizing a single type of benefit. My pre-filed direct testimony in Commission docket number E-2, Sub 1300, identified five principles of "proactive" transmission planning:

1. Proactively plan for future generation and load by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.
2. Account for the full range of transmission projects' benefits and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
3. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.
4. Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.
5. Jointly plan across neighboring interregional systems to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

As noted above, load growth increases the need for transmission to interconnect new loads and accommodate higher demand, as well as interconnecting the generation needed to serve those loads and meet carbon reduction requirements. Proactive multi-value transmission planning should identify opportunities to use the same transmission investment to serve both purposes. This could include transmission expansion that allows new renewable resources to interconnect in areas where new loads are proposing to interconnect, or alternatively increases deliverability between renewable resource areas and areas experiencing load growth.

Q: WHAT DO YOU MEAN BY "SYNCHRONIZED" GENERATION AND TRANSMISSION PLANNING?

A: A synchronized generation and transmission planning process minimizes total costs for generation plus transmission. MISO and others have successfully used a synchronized generation and transmission planning approach to minimize total costs to ratepayers. As illustrated in the following chart from a MISO transmission planning study, synchronized planning allows one to minimize the total cost to ratepayers of generation plus transmission by building the optimal amount of transmission.[54] The red area on the left of the chart represents an underinvestment in transmission that results in higher generation costs and therefore total costs to customers. The blue area on the right shows a theoretical overinvestment in transmission, though given Duke's large transmission need and the very large net benefits it has found for incremental transmission investment, Duke is almost certainly on the left side of an equivalent chart. The goal of synchronized planning should be to minimize the total cost of generation plus transmission, as occurs in the white area in the middle of the chart. For Integrated Resource Plans to truly be "integrated," they must account for the transmission needed to realize an optimal generation buildout.

[54] Midcontinent Indep. Sys. Operator, *Regional Generation Outlet Study* at 3 (Nov. 19, 2010), https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf.

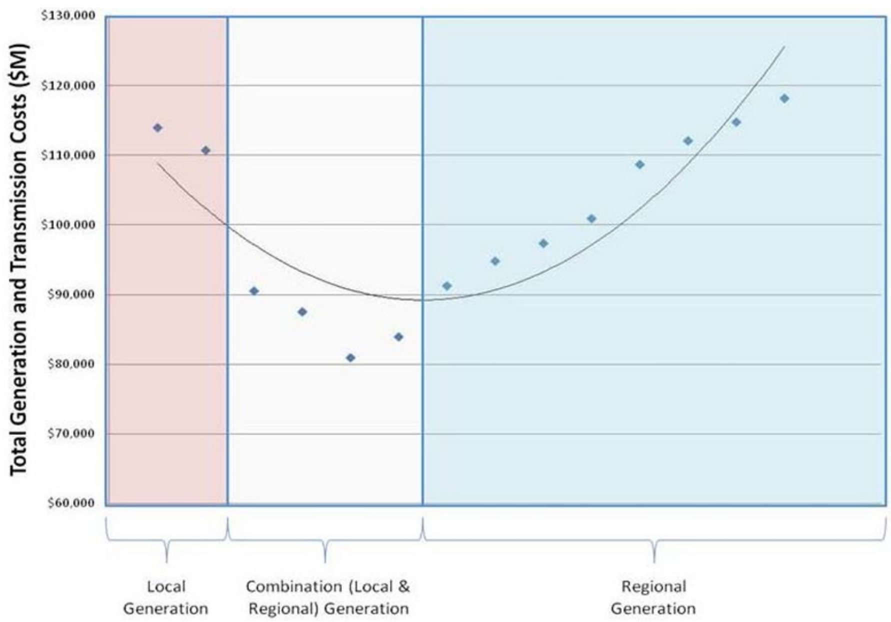

Figure 1: MISO chart showing how synchronized planning minimizes ratepayer costs[55]

Q: HAVE OTHER REGIONS SUCCESSFULLY PLANNED AND BUILT NET BENEFICIAL TRANSMISSION LINES USING THESE APPROACHES?

A: Yes. In my pre-filed direct testimony in Commission docket number E-2, Sub 1300, I reviewed the many benefits of proactive multi-value planning that have been realized by regions and states including MISO, SPP, Nevada, and Colorado, so I will not reiterate those points here. I incorporate by reference my prior testimony concerning the benefits of proactive multi-value planning.[56]

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[55] *Id.*

[56] Direct Testimony and Exhibits of Michael Goggin on Behalf of The Sierra Club, *In the Matter of Application of Duke Energy Carolinas, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina and Performance-Based Regulation*, Docket No. E-2, Sub 1300 (N.C.U.C. Mar. 27, 2023), https://starw1.ncuc.gov/NCUC/PSC/PSCDocumentDetailsPageNCUC.aspx?DocumentId=28050cdb-9ea0-4c48-9c90-d41290d58e92&Class=Filing.

Q: CAN THE CTPC'S MVST APPROACH BE USED TO PLAN THE NEEDED TRANSMISSION?

A: While critical details of that approach are still being finalized, that process may provide a workable means of planning the needed transmission, though Commission oversight will be required to address some apparent shortcomings.

First, there does not appear to be any guarantee that Duke will use the MVST process to actually plan the transmission it will use to meet its future needs. CTPC still retains economic, reliability, and public policy planning studies, and the result of using those siloed planning approaches could be to plan suboptimal transmission expansion. To address that concern, the Commission should direct Duke that all transmission brought for its approval must be planned through MVST.

Second, CTPC processes have so far failed to adequately consider high-capacity transmission expansion solutions. Duke answered "no" to data request question SACE 27-2-2:[57] "Were any greenfield 230 kV and 500-kV upgrades evaluated in the 2023 Public Policy study?" and provided the explanation that "There were no transmission needs identified in the study that warranted a greenfield transmission solution." The study itself notes that "A greenfield 230kV transmission network was identified as a potential long-term solution for multiple resource types desiring to interconnect in the southwest DEC transmission

[57] Attached as **Exhibit MG-8**.

system and is planned to be studied in the 2024 MVST study to determine if this solution needs to be included in the local transmission plan."[58] While it is encouraging that Duke plans to evaluate that solution in the 2024 study, the 2023 study did not appear to evaluate the potential design, cost, or value from displacement of other grid upgrades from this greenfield solution. Unfortunately, the report does not mention evaluating any greenfield solutions for DEP or other potential greenfield solutions for DEC. The study also did not appear to evaluate replacing existing equipment with higher-voltage equipment, as the study indicates all "Estimated upgrade costs are for a standard reconductor for transmission lines or replacement with a larger size for transformers."[59]

In many cases, it is likely that greenfield or high-voltage transmission expansion could have more efficiently met the identified needs than lower-voltage upgrades of existing transmission. The failure to identify greenfield transmission needs also contradicts Duke's statement at page 39 of Appendix L of the CPIRP that "The [2023] study results and any identified greenfield 230 kV and/or 500 kV transmission line needs will be discussed and included in the NCTPC study report and will be included in future Carolinas Resource Plans along with recommendations for potential transmission expansion projects." Given the much higher capacity and lower $/MW-mile costs for high-voltage and

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[58] NCTPC, *Report on the NCTPC 2023 Public Policy Study, Draft Report* (May 17, 2024) at 23, http://www.nctpc.org/nctpc/document/REF/2024-05-17/NCTPC_2023_Public_Policy_Study_Draft%20Report%2005172024.pdf.

[59] *Id*., at 20, 24.

double-circuit transmission indicated in Table 3 above, Duke should be primarily relying on those higher-capacity solutions to meet its needs going forward.

Q: IN ADDITION TO UTILIZING PROACTIVE MULTI-VALUE TRANSMISSION PLANNING, CAN DUKE ALSO RELY ON THE INTERCONNECTION QUEUE?

A: Upgrades to existing lines are valuable because they allow near-term transmission expansion by minimizing the need for permitting new right-of-way, but in most cases they need to be complemented by greenfield and higher-capacity transmission expansion to find the optimal solution to all long-term needs. This is particularly true when there is little to no existing transmission infrastructure in undeveloped low-cost renewable resource areas, so greenfield transmission expansion is required to tap those resources. For example, high-voltage and greenfield transmission expansion will be required to access land-based and offshore wind resources in eastern North Carolina, given the size of the resource and the lack of high-voltage transmission in that part of the state.

Duke and the CTPC appear to have heavily relied on the generator interconnection applications through the DISIS process to determine where future resources will interconnect, so their planning processes may be missing opportunities to tap new low-cost renewable resource areas. While the current interconnection queue can be a useful input for transmission planning by identifying areas where developers are interested in building generation projects, it should not be the only input. The location of proposed generation projects in the queue is heavily shaped by where there is currently available transmission capacity, and greenfield transmission can create new unconstrained entry points for renewables. As a result, Duke should also proactively plan transmission to new areas that are promising for low-cost renewable development. One way to do that is by using the results of a "Request for Proposals" or other solicitation to get market cost data from proposed generators in different locations. This would allow developers to provide Duke with information about the cost of generation in various potential locations. Then, Duke can determine the cost of potential grid upgrade portfolios to accommodate groups of those projects, and choose the grid upgrades that minimize the total generation plus transmission cost. Duke's annual renewable energy solicitations can serve as an important source of that cost information.

Q: CAN YOU PROVIDE EXAMPLES OF THE TYPE OF TRANSMISSION UPGRADES DUKE SHOULD BE EVALUATING IN ITS PLANNING PROCESS?

A: Yes, the following are examples of the type of greenfield and high-voltage projects Duke and CTPC should be evaluating as potential solutions in its transmission planning processes. Some of these potential projects were identified in a conceptual map in Duke's 2022 Carbon Plan,[60] and these concepts

[60] Duke 2022 Proposed CPIRP, App'x P at 21, Figure P-3, Docket No. E-100, Sub 179 (May 16, 2022), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=1b035aef-cdb1-4a8a-ae0c-599d02ab61cf.

are also informed by recent DISIS and transitional interconnection queue applications that provide indicators of where generation developers are interested in building projects.

Q: ARE THERE EXAMPLES OF POTENTIAL GREENFIELD OR HIGH-VOLTAGE GRID UPGRADES IN DEP's FOOTPRINT IN EASTERN NORTH CAROLINA?

A: Yes. In recent DISIS queue applications, solar developers have indicated significant interest in the Jacksonville to New Bern to Goldsboro corridor in eastern North Carolina.[61] The RZEP projects increase transfer capacity by upgrading existing lines in this area, including the Lee-Milburnie 230-kV upgrade included in RZEP 2.0. However, there is still unmet need for additional transmission expansion, particularly to interconnect wind resources.

Duke's 2022 Carbon Plan proposed a radial 500-kV connection between the Wake and New Bern substations to accommodate offshore wind.[62] As shown in Table 3 above, the large transfer capacity of 500-kV transmission offers significant economies of scale relative to lower-voltage transmission. A looped network of at least two 500-kV lines may be able to even more efficiently accommodate the significant combined potential for solar, land-based wind, and offshore wind in this area while helping to overcome contingency concerns that

[61] Roberts Direct Testimony, at 26-27.

[62] Duke 2022 Proposed CPIRP, App'x P at 17, Docket No. E-100, Sub 179 (May 16, 2022), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=1b035aef-cdb1-4a8a-ae0c-599d02ab61cf.

would limit the transfer capacity on a single radial 500-kV line. Complementary daily and seasonal output profiles between solar and wind resources would increase the utilization factor of these upgrades. The output profiles of solar, land-based wind, and offshore wind shown in the 2023 Effective Load Carrying Capability study included in the CPIRP demonstrate the complementarity of these resources. The presence of land-based wind, offshore wind, and solar similarly provides valuable optionality for filling the line with other types of resources if one type fails to develop, as proactive transmission development must significantly precede generation procurement given the long lead time required to plan, permit, and build transmission.

Q: ARE THERE EXAMPLES OF POTENTIAL GREENFIELD OR HIGH-VOLTAGE GRID UPGRADES IN SOUTHERN NORTH CAROLINA AND NORTHERN SOUTH CAROLINA?

A: A map in Duke's 2022 Carbon Plan[63] suggests adding a 500-kV loop south from Cumberland, through South Carolina, and then connecting to the 500-kV network southwest of Charlotte, North Carolina. This will help to move renewable generation from eastern and southeastern North Carolina towards the Charlotte load center and facilitate the interconnection of new renewable resources in South Carolina. Adding 500-kV substations in these renewable resource areas is particularly valuable as it allows lower-voltage lines that are

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[63] *Id.* at 21.

currently congested from delivering power west or north towards the existing 500-kV network to instead flow onto the new 500-kV loop, significantly increasing interconnection capacity in the area.

The map in Duke's 2022 Carbon Plan also proposed a conceptual solution of building two greenfield 230-kV loops through South Carolina, and tapping the 500-kV network where the new 500-kV line delivering renewables from the eastern Carolinas would also tie in. Either solution, or some combination of them, should be examined in more detail.

Q: SHOULD OTHER POTENTIAL EXPANSIONS OF THE 500-KV NETWORK BE EVALUATED?

A: Yes they should, given the economies of scale associated with 500-kV transmission. The map in Duke's 2022 Carbon Plan also proposes closing the hole between the DEC and DEP systems on the northeastern end of Duke's 500-kV network. This could be achieved by building the long-discussed Durham - Parkwood 500-kV line, or other potential upgrades in the Durham area and between Roxboro and Sadler, North Carolina. Closing this hole should increase the reliability and resilience of the 500-kV backbone while also allowing new renewable resources to more easily flow along the northern part of the existing 500-kV loop.

Expanding ties between DEC and DEP will be particularly important for enabling efficient operations as the DEC and DEP Balancing Authorities merge. This is extremely valuable with today's generation mix, as Duke's reserve margin can be reduced if there is sufficient transmission to take full advantage of the diversity in the timing of peak load and conventional generator outages between DEP and DEP, and this benefit will only become more important at higher renewable penetrations. CTPC's 2023 Public Policy Study shows flows between the two Balancing Authorities increase to nearly 4 GW in the high-renewable future.[64] Strengthening and expanding the 500-kV backbone will help tap into geographic diversity in output profiles between solar resources in the DEC footprint in the central and western parts of the Carolinas and DEP wind and solar resources in the eastern part of the states, reducing the total variability of their output and increasing the dependable capacity value they provide for meeting resource adequacy needs. With both current and future generation mixes, expanded transmission also provides significant production cost savings by allowing low-cost generation in one Balancing Authority to displace higher-cost generation in the other, based on real-time variations in the load, generation mix, and fuel prices in each region. A strong 500-kV backbone will also play a critical role in enabling the expanded interregional power flows discussed in the final section of my testimony, particularly if 500-kV ties to neighboring grid operators are built.

[64] CTPC, Presentation: *TAG Meeting March 22, 2024: Webinar FINAL* at 16 (Mar. 22, 2024), http://www.nctpc.org/nctpc/document/TAG/2024-03-22/M_Mat/TAG_Meeting_Presentation_for_03-22_2024_FINAL%20NO%20Maps.pdf.

V. The Commission should require Duke to evaluate expanding ties to neighboring grid operators

Q: HOW DOES EXPANDING TIES TO OTHER UTILITIES AFFECT COST AND RELIABILITY FOR DUKE RATEPAYERS?

A: Expanding transmission ties to neighboring grid operators can significantly improve reliability and reduce cost. Utilities experience peak demand and generator outages at different times, and tapping into this diversity significantly reduces the planning reserve margin that is needed to maintain the same level of reliability.[65] That diversity also increases resilience during extreme weather events, as extreme weather systems move over time and tend to be at their most severe in relatively small geographic areas. As a result, at least one of Duke's neighboring power systems, or a neighbor of a neighbor, is likely to have available capacity during Duke's time of peak need. A stronger regional grid allows all utilities to share in those resilience benefits and maintain the same

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[65] For example, MISO finds around $2.4 billion in annual benefits because "MISO's large geographic footprint allows members to lower planning reserve margins (PRM), ultimately reducing the amount of required installed capacity. Much of the value MISO creates comes from the value of sharing capacity across MISO's large geographic footprint by setting requirements for a system peak instead of each balancing authority keeping reserves for their own region. Savings are generated because MISO members do not need as much capacity for the same level of reliability." MISO, *MISO Value Proposition Annual View, 2023 Overview* at 6 (Mar. 2024), https://cdn.misoenergy.org/2023%20Value%20Proposition%20Annual%20View%20-%20Detailed%20Report%20Final632082.pdf?v=20240306103856. Similarly, PJM finds $1.2-1.8 billion in annual savings because "There is considerable diversity in electrical use patterns in the large PJM footprint; not all areas peak at the same time of the year. As a result, resources in one area of the system are available to help serve other areas at peak times, and a smaller reserve is required. In addition, the large and varied resource fleet across the entire PJM region spreads the generator outage risk across a larger collection of generators, improving reliability." PJM, *PJM Value Proposition* at 2, https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx.

level of reliability with a lower reserve margin. Ties also significantly reduce production costs by allowing Duke to import lower-cost power from neighbors when it is available and profitably export power when its supply is greater than its demand.

Q: HOW WILL INCREASING RENEWABLE PENETRATIONS AFFECT THE NEED FOR TIES TO NEIGHBORING GRID OPERATING AREAS?

A: Capturing diversity in renewable output across large geographic areas is essential for cost-effectively achieving higher renewable penetrations. Geographically diverse renewables, as well as a more diverse portfolio of solar, land-based wind, and offshore wind resources, provide more dependable capacity and less variable output because their output profiles are weakly or negatively correlated. Multiple studies have confirmed that expanding transmission ties within and among grid operators to access that diversity is essential for cost-effective decarbonization.[66] For example, stronger ties to neighboring grid operators will allow Duke and other utilities in the Southeast to

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[66] For example, see Patrick Brown and Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule (Jan. 2021), https://www.sciencedirect.com/science/article/pii/S2542435120305572; NREL, *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study* (Sept. 2021), https://ieeexplore.ieee.org/document/9548789; Alexander E. MacDonald, et al., *Future Cost-Competitive Electricity Systems and Their Impact on US CO2 Emissions*, Nature Climate Change 6, 526–531 (2016), https://www.nature.com/articles/nclimate2921.

export solar during the day and in the summer and import wind from other areas at night and during the winter.[67]

To capture this benefit, Duke's transmission plans should be coordinated with the generation and transmission plans of neighboring grid operators. Duke's queue projects are currently triggering affected system studies in neighboring grid operating areas, and vice versa. Coordinated planning, like what MISO and SPP have recently adopted,[68] is more efficient than relying on affected system studies to account for those impacts.

For example, Duke's planning should account for Dominion Energy's approved plans to interconnect at least 2.6 GW of offshore wind into southeast Virginia, as well as further potential offshore wind development delivering into Virginia. In addition to more efficiently accommodating changes in network flows, coordinated planning should offer opportunities to benefit both Duke and Dominion ratepayers by taking advantage of the low correlation between the output profiles of Dominion's offshore wind and Duke's solar. The cost of non-firm transmission imports from the PJM Interconnection is low at $0.67/MWh,[69]

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[67] Americans for a Clean Energy Grid, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.* at 21-22 (Oct. 2020), https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf.

[68] SPP and MISO, *SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes* (Dec. 20, 2022), https://www.spp.org/documents/68518/spp-miso%20jtiq%20study%20updated%20white%20paper%2020221220.pdf.

[69] PJM Manual 27: Open Access Transmission Tariff Accounting, *6.1 Point-to-Point Transmission Service Accounting Overview* (2023), https://www.pjm.com/directory/manuals/m27/index.html#Sections/61%20PointtoPoint%20Transmission%20Service%20Accounting%20Overview.html.

so Duke can use market transactions to maximize low-cost energy purchases and cancel out variability by capturing diversity in wind and solar output patterns.

Q: ARE THERE OPPORTUNITIES FOR DUKE TO SIGNIFICANTLY EXPAND TRANSMISSION TIES WITH NEIGHBORING GRID OPERATORS?

A: Yes. Even a cursory glance at a map of the transmission system indicates multiple opportunities for short high-voltage connections between Duke's system and that of PJM and other neighboring grid operators. In the case of PJM, a 500-kV line could likely be extended from Duke's Person substation to the Clover substation in Dominion's portion of PJM. Another 500-kV connection to PJM could likely be made between the Pleasant Garden 500-kV substation on Duke's transmission system and the Axton substation in AEP's territory within PJM's system. A past proposal to build a 500-kV line within PJM between Clover and Axton did not trigger significant network upgrades elsewhere on the PJM system,[70] likely indicating those substations could accommodate expanded ties with Duke. As shown in Table 3 above, 500-kV lines offer significant increases in transfer capacity at a low cost due to transmission's economies of scale.

These upgrades could likely be completed soon enough to facilitate Duke's compliance with the interim carbon-reduction requirement in House Bill 951. Dominion recently completed two new 500-kV lines within 5 years of

[70] PJM, *PROJECT PROPOSAL: Axton to Clover 500 kV* at e.g., 4-5 (Feb. 27, 2015), https://www.pjm.com/-/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/redacted-public-proposals/201415-1-8d-dominion-transource-public-redacted-version-axton-clover-500kv.ashx.

receiving approval from PJM.[71] These projects each involved building 500-kV transmission on more than 60 miles of new right-of-way,[72] more than would likely be required for the PJM tie projects discussed above. Duke may be able to share some of the costs of these upgrades with PJM members, as PJM and SERTP split costs based on displacement of regional transmission project needs if a project is included in both regions' plans.[73]

Similar opportunities for expanding ties to other neighboring utilities should also be explored. For example, RZEP projects in the southern part of Duke's footprint could easily be extended to increase transfer capacity with other South Carolina utilities.

Q: CAN THE NET BENEFITS OF EXPANDING TIES WITH NEIGHBORING UTILITIES BE EVALUATED IN THE PROACTIVE MULTI-VALUE PLANNING ANALYSIS YOU PROPOSE ABOVE?

A: Yes. In the proactive multi-value transmission planning analysis discussed above, the Commission should require Duke to evaluate opportunities for expanding transmission interconnections with neighboring Balancing Authorities,

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[71] Dominion High Voltage Holdings, *Artificial Island Supplemental Proposal Response: Dominion High Voltage Project P2013_1-1C* at 2 (Sept. 12, 2014), https://www.pjm.com/-/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2013-1-1c-dominion-high-voltage-public-artificial-island-project.ashx.

[72] PJM, *PROJECT PROPOSAL: Axton to Clover 500 kV* at 12 (Feb. 27, 2015), https://www.pjm.com/-/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/redacted-public-proposals/201415-1-8d-dominion-transource-public-redacted-version-axton-clover-500kv.ashx.

[73] PJM, *Schedule 12-B: Allocation of Costs of Certain Interregional Transmission Projects Located in the PJM and SERTP Regions* (2024), https://agreements.pjm.com/oatt/23534.

as well as the net benefits of these expanded ties. The Commission should require Duke to bring net beneficial tie expansion projects to the Commission for approval, and negotiate cost allocation with neighboring utilities to reflect the benefits they also receive from these upgrades.

Q: DO SOUTHEASTERN REGIONAL TRANSMISSION PLANNING ("SERTP") PROCESSES CURRENTLY USE MULTI-VALUE PLANNING?

A: No. The SERTP processes greatly understate the benefits of transmission by only accounting for the benefit of deferring smaller-scale transmission upgrades needed to meet reliability criteria. SERTP also uses siloed planning instead of multi-value transmission planning, with separate processes for evaluating reliability, economic, and public policy projects.[74]

Q: HAVE THERE BEEN ANY CONSEQUENCES TO SERTP NOT USING PROACTIVE MULTI-VALUE PLANNING AND FAVORING "SILOED" PROCESSES?

A: SERTP has not successfully driven large-scale transmission investment. In June 2023, Americans for a Clean Energy Grid released a report card scoring regions based on their transmission planning methods and measured their

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[74] *See, e.g.*, North Carolina Transmission Planning Collaborative, *Report on the NCTPC 2022-2032 Collaborative Transmission Plan*, 9–12 (Feb. 21, 2023), http://www.nctpc.org/nctpc/document/REF/2023-02-21/2022%20NCTPC%20Report%2002_21_2023_FINAL.pdf; *see also*, North Carolina Transmission Planning Collaborative, *TAG Meeting June 21, 2023 Webinar*, 9–12, http://www.nctpc.org/nctpc/document/TAG/2023-06-21/M_Mat/TAG_Meeting_Presentation_for_06-21_2023_FINAL.pdf (discussing the separate studies for reliability and public policy projects in the NCTPC.).

success in building transmission. The Southeast was the only region in the country to receive an "F" grade, and the only region that failed to build any transmission lines at or above 300-kV during the period 2020-2022.[75] Similarly, DOE's Transmission Needs Study found the Southeast greatly lags other regions of the country in building transmission, as shown in the DOE chart below.[76] Continuing to rely on siloed processes that understate the benefits of transmission cannot efficiently drive proactive transmission development.

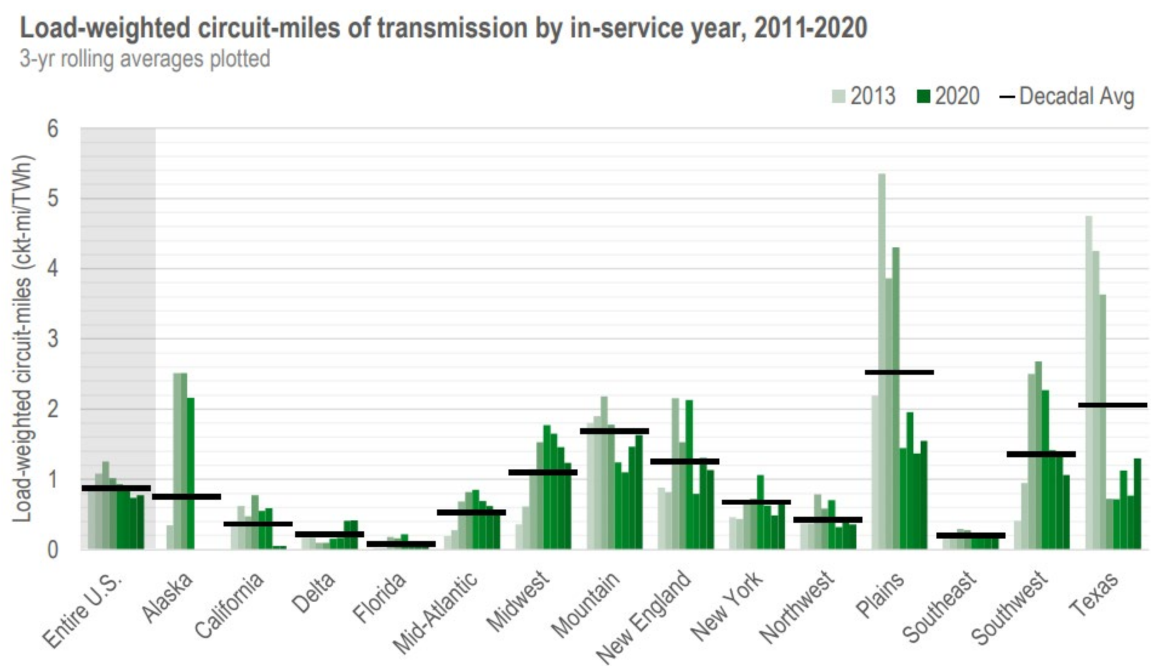

Figure 2: DOE chart showing transmission construction by region, with the Southeast lagging other regions

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[75] *See* Zimmerman, et al., *Transmission Planning and Development Regional Report Card* at e.g., 7, Am. for a Clean Energy Grid (June 2023), https://www.cleanenergygrid.org/wp-content/uploads/2023/06/ACEG_Transmission_Planning_and_Development_Report_Card.pdf.

[76] DOE, *National Transmission Needs Study* at 23-24 (Oct. 2023), https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

Q: WHAT CAN THE COMMISSION DO TO MAKE SERTP PLANNING MORE EFFECTIVE?

A: The Commission should encourage Duke to propose and advocate for SERTP to conduct synchronized proactive multi-value transmission planning beginning in the first round of studies initiated following issuance of an order in this case, and repeat such a study with up-to-date information in each subsequent SERTP planning cycle. The scope of that study should be to identify the optimal transmission expansion among Balancing Authorities in SERTP and with neighboring planning regions, accounting for the multiple categories of transmission benefits discussed later in my testimony, as well as expected changes in the generation mix and the need for transmission during high-impact and low frequency events. I also respectfully recommend that the Commission should advocate at SERTP for its participating utilities and states to adopt a workable cost allocation mechanism for the transmission projects identified in those planning studies. Other regions like MISO and SPP have found broad regional cost allocation to be the most workable mechanism for paying for high-voltage transmission that provides benefits to an entire region.

FERC Order 1920, issued earlier this month, requires regional transmission planning entities like SERTP to implement many of the planning reforms discussed above, and for their member states to negotiate a regional cost allocation method. The North Carolina Utilities Commission can therefore directly take on a leadership role by advocating for effective proactive multi-value transmission planning and a workable cost allocation mechanism for high-voltage transmission that benefits the entire region in those discussions.

VI. Increasing Duke's dependence on gas generation exposes ratepayers to reliability and economic risks

Q: DID DUKE ADEQUATELY ACCOUNT FOR THE RELIABILITY RISKS OF GAS GENERATORS IN ITS CAPACITY VALUE ACCREDITATION?

A: No, because Duke has not reduced the accredited capacity value of gas generators to account for the reliability risks of correlated gas generator outages, like those experienced during Winter Storm Elliott and other recent cold snaps. Capacity value is a measure of a resource's dependable contribution towards meeting electricity demand during peak periods, and it is a key input assumption for economic generator capacity expansion modeling like Duke used in its proposed CPIRP. Instead of reducing the capacity value of gas generators, Duke added 2.5% to the winter reserve margin based on the higher observed rate of generator failures in recent years, including during extreme cold weather events like Winter Storm Elliott.[77]

Increasing the winter reserve margin effectively socializes the risk of correlated failures of gas and other conventional generators. Instead, Duke should accredit that risk to the generators that cause it by reducing their accredited capacity value, which will ensure that Duke's economic modeling

[77] Direct Testimony of Wintermantel and Benson, at 13-15.

properly values potential resources and selects an optimal generation portfolio. This could be done by using a consistent framework for evaluating all generators' capacity value contributions. Duke's Effective Load Carrying Capability ("ELCC") analysis accounts for how correlated output profiles of wind, solar, or storage resources reduce their capacity value, but not how similar correlations reduce the capacity value of conventional generators. To ensure a level playing field and prevent suboptimal ratepayer outcomes in its resource selection, Duke should calculate the capacity value contributions of both renewable and conventional generators, using ELCC or another method that accounts for the correlated outages of conventional generators.

If Duke were to fully account for the impact of correlated outages and derates on the dependable capacity of its proposed gas generators, the actual capacity value of those plants would be significantly lower. This would make renewable and storage resources more attractive relative to gas. Overestimating the capacity value of new gas generation likely results in an economically suboptimal resource mix. Building more gas generating capacity to compensate for failures of other gas generators is an exercise in futility if the fundamental factors causing correlated forced outages of gas generation during peak demand periods are not addressed. This is particularly true if new gas generators are susceptible to the same outage causes as the existing fleet, like dependence on the same interstate gas pipelines or gas production areas.

Q: WHAT DO YOU MEAN BY CORRELATED OUTAGES?

A: Over the last decade, Duke and the broader electric utility industry have experienced multiple reliability events in which a large number of conventional power plants fail concurrently due to extreme weather, fuel supply disruptions, and other factors. FERC-NERC reports and regional analyses have documented that correlated forced outages and derates of gas generators were a primary cause of reliability problems during extreme cold weather events that affected Duke and other utilities, including Winter Storm Elliott,[78] Winter Storm Uri,[79] the 2018 Bomb Cyclone,[80] the 2018 South Central Cold Snap,[81] and the 2014 Polar Vortex.[82] In particular, gas accounted for 63% of unplanned outages and derates during Winter Storm Elliott,[83] and 55% during Winter Storm Uri[84] and the 2014

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[78] FERC and NERC, *December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations* at e.g., 5 (September 21, 2023), https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[79] FERC and NERC*, The February 2021 Cold Weather Outages in Texas and the South Central United States* at 16-17 (2021)*, https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.*

[80] U.S. Energy Info. Admin.*, January's Cold Weather Affects Electricity Generation Mix in Northeast, Mid-Atlantic (Jan. 23, 2018), https://www.eia.gov/todayinenergy/detail.php?id=34632.*

[81] FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* at 57-58, 96-97 (July 2019), https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf.

[82] NERC*, Polar Vortex Review* at iii (Sept. 2014)*, https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.*

[83] FERC and NERC, *December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations* at e.g., 5 (September 21, 2023), https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[84] FERC and NERC*, The February 2021 Cold Weather Outages in Texas and the South Central United States at 16-17 (2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.*

Polar Vortex,[85] while coal accounted for a large share of the remainder. Correlated gas generator outages have occurred due to equipment failures, shortages of gas supply due to the freezing of wellheads, and pipeline failures or constraints. Correlated outages and derates of gas generators have also played a major role in reliability concerns during extreme heat, including last summer's heat wave in ERCOT and the 2022[86] and 2020[87] heat waves in California.

Q: HAVE STUDIES QUANTIFIED THE IMPACT OF GAS GENERATOR CORRELATED OUTAGES?

A: Recent analysis by Astrape for Dominion's portion of PJM, which is likely to experience similar weather and gas supply issues as Duke, shows that accounting for these correlated generator outages significantly reduces the calculated reliability contributions of conventional generating resources. Specifically, Astrape found that accounting for correlated outages can cause an additional 10% reduction in gas resources' capacity contributions during the summer, and 20% in the winter, beyond the forced outage rate that is typically assumed.[88]

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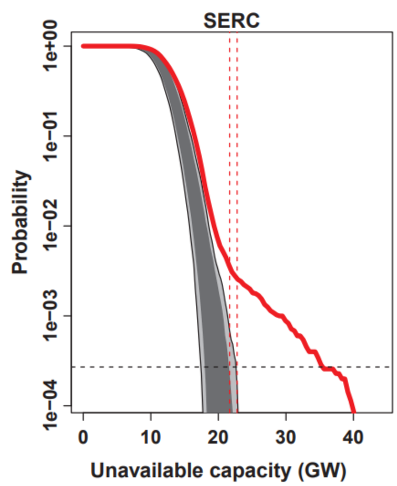
[85] NERC*, Polar Vortex Review at iii, 13 (Sept. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.*

[86] Regenerate California, *California's Underperforming Gas Plants* at e.g., 7-8 (July 2023), https://caleja.org/wp-content/uploads/2023/06/2023-Regenerate-Heat-Wave-Report.pdf.

[87] CAISO, *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave* at e.g., 47-48 (Jan. 2021), http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[88] Joel Dison et al., Astrapé Consulting, *Accrediting Resource Adequacy Value to Thermal Generation* at 6 (Table ES1) (Mar. 30, 2022),

Another paper used NERC data[89] to demonstrate that conventional generators experience common mode correlated outages many times more frequently than is predicted under the assumption that individual plant outages are uncorrelated independent events. As shown below, in the SERC region that includes Duke, simultaneous winter generation outages (red line) are roughly twice the level of outages that would be expected under the assumption that generator outages are uncorrelated independent events (gray area), with about 15-20 GW more concurrent outages than expected.[90]



https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf (calculated by taking the difference between the 95% accreditation under current methods, and what the study found as the actual summer credit of 84.7% and winter credit of 76.1%).

[89] Sinnott Murphy, et al., *Resource adequacy risks to the bulk power system in North America*, 212 Applied Energy 1360, 1372, https://www.sciencedirect.com/science/article/pii/S0306261917318202.

[90] *Id.* at 1366, Fig. 4.

Figure 3: Chart from journal article showing that simultaneous generator outages (red) in Southeast are twice as high as expected if they were actually uncorrelated events (gray area)[91]

Q: HOW DO GAS GENERATORS COMPARE TO BATTERIES IN THEIR CONTRIBUTION TO FLEXIBILITY AND OTHER RELIABILITY SERVICES?

A: Flexible battery resources are far more valuable than gas generators for managing power system variability. Flexibility will become even more important as Duke reaches higher renewable penetrations. Despite Duke's claims that gas generators will help integrate renewables,[92] their inflexibility can significantly impede renewable integration. Gas generators, and particularly the gas combined cycle generators that comprise more than 75% of the gas capacity Duke is proposing, are quite inflexible relative to batteries. The steam generator component of a combined cycle has relatively slow ramp rates, high minimum output levels, and long startup and shutdown time requirements, while combustion turbines typically require nearly 10 minutes to ramp to full output. In contrast, batteries offer nearly instantaneous response with no minimum output level. Batteries can also absorb power during periods of low demand or high supply, including renewable output that would have been curtailed. Fossil generators cannot absorb excess power. Gas generators must start up and be kept online to provide flexibility and other ancillary services, while batteries can start up within seconds to provide flexibility, voltage and reactive support, or

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[91] *Id.*

[92] *E.g.*, Duke Proposed CPIRP Ch.4, p.28.

other reliability services. Batteries also offer at least twice the dispatch range that conventional generators offer, as they can ramp between fully charging and fully discharging, while even flexible gas generators have a limited dispatch range. As a result, batteries are far more valuable than gas generators on a power system with a high renewable penetration. Deploying gas generators, and particularly combined cycle generators, instead of batteries will significantly increase renewable curtailment because gas generators are not flexible enough to reduce their output during many periods of high renewable output and cannot absorb excess renewable generation. Batteries are particularly valuable on power systems with a large amount of solar generation, as they can absorb excess solar power midday and then release that energy during evening peak demand, while also helping with morning and evening ramps.

Q: DOES GAS GENERATION POSE OTHER ECONOMIC RISKS?

A. Yes. Increasing Duke's dependence on gas generation expands its exposure to fuel price risk and the risk of future environmental regulations on gas generation. The variability and uncertainty of natural gas prices poses a major risk to ratepayers, as fuel costs are passed through directly to customers. Gas prices are highly volatile on both a day-to-day basis due to weather, and on a year-to-year basis due to economic and geopolitical factors. Expanding Liquefied Natural Gas ("LNG") exports are increasingly tethering domestic natural gas prices to global prices, coincident with large fluctuations in global prices due to Russia's invasion of Ukraine and the risk of wider conflict in the Middle East.

Europe and other regions continue to expand their imports of LNG, while North America is expected to more than double its LNG export capacity by the end of 2027 once facilities that have already been permitted come online.[93] As a result, U.S. natural gas prices will increasingly be affected by global geopolitical and economic factors.

U.S. natural gas prices may also experience greater volatility as more gas is used domestically for electricity generation, and extreme weather events that affect both gas and electricity demand increase in magnitude and frequency due to climate change. Extreme cold weather events like Winter Storm Elliott not only impose a reliability risk on ratepayers as Duke increases its reliance on gas, but also an economic risk because ratepayers are subject to price volatility during these extreme events.

Q: ARE GAS GENERATORS AT RISK FROM FUTURE ENVIRONMENTAL REGULATIONS?

A: Yes, environmental regulations could increase the cost of gas generation or even make those generators stranded assets. This could include more stringent regulation of greenhouse gases, including both carbon dioxide emissions at the generator or upstream emissions of methane. EPA has indicated that it intends to develop comprehensive rules to reduce greenhouse

[93] EIA, *LNG export capacity from North America is likely to more than double through 2027* (November 13, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60944.

gas emissions from all gas generators,[94] as emissions from existing gas generators were not regulated under the rules finalized earlier this month. These future EPA rules could significantly increase the cost of or limit the use of Duke's existing gas generators as well as the nearly 9 GW of gas it plans to build in its proposed CPIRP.

The ability of proposed new gas generators to burn hydrogen in the future is far from a panacea for these concerns, as the availability and economic viability of hydrogen, and particularly renewable or "green" hydrogen, is still highly uncertain. The technologies required for producing "green" hydrogen using electrolysis, transporting hydrogen, and storing hydrogen have not been commercially deployed at scale, and face significant economic challenges. Costly new infrastructure will be required, as hydrogen cannot be transported using existing natural gas pipelines.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

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[94] EPA, *Statement from EPA Administrator Michael S. Regan on EPA's approach to the power sector* (Feb. 29, 2024), https://www.epa.gov/newsreleases/statement-epa-administrator-michael-s-regan-epas-approach-power-sector.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony and Exhibits of Michael Goggin on Behalf of the Natural Resources Defense Council, the Sierra Club, the Southern Alliance for Clean Energy, and the North Carolina Sustainable Energy Association, either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 28th day of May, 2024.

/s/ Nick Jimenez

EXHIBIT MG-1

Michael Goggin

Education:

Harvard University class of 2004, B.A. *cum laude* in Social Studies

- Wrote thesis "Is it Time for a Change? Science, Policy, and Climate Change"

Experience:

Grid Strategies Vice President February 2018-present

- Serve as an expert consultant on electricity transmission, grid integration, reliability, market, and public policy issues for environmental and clean energy industry clients
- Have testified before FERC and in dozens of state regulatory commission cases
- Actively engaged in NERC Standards development processes related to renewable and storage resources

AWEA Senior Director of Research, other titles February 2008-February 2018

- Led team responsible for all American Wind Energy Association analysis
- Served as primary technical and economic expert on market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (RTO transmission and market design), and federal levels (FERC transmission, interconnection standard, grid integration, and market design cases; EPA carbon policy)
- Directed economic and power sector modeling to inform AWEA's policy strategy and support advocacy positions
- Communicated with the press and policy makers about wind energy
- Other titles included Electric Industry Analyst, Senior Analyst, Manager of Transmission Policy, Director of Research

Sentech, Inc. Research Analyst October 2005-February 2008

- Conducted economic analyses of solar, wind, geothermal, hydrogen, and energy storage technologies for U.S. Department of Energy officials
- Provided analytical support for DOE's renewable energy R&D funding decisions

Union of Concerned Scientists Clean Energy Intern May 2005-October 2005

- Worked with the legislative and field staff to promote the inclusion of pro-renewable energy measures in the Energy Policy Act of 2005

State Public Interest Research Groups Policy Analyst August 2004-May 2005

- Analyzed and advocated for clean energy policies at the state and federal level

Publications available at https://gridstrategiesllc.com/reports/

EXHIBIT MG-2

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please provide evidence to support the claim on page 21 of Appendix L that "Outage coordination groups currently accommodate about as many outages as can be accommodated and maintain reliable, single contingency operations in accordance with NERC Reliability Standards and prudent outage planning." This evidence could include documentation from outage coordination groups, or data indicating the seasons and timeframes in which planned transmission outages are scheduled and the amount of outages recently scheduled in those periods.

Response:

32-4: See the Companies' response to SACE DR 31-1-1.

Responder: Sammy Roberts, GM, Grid and Operations Planning

EXHIBIT MG-3

EXHIBIT MG-3

CONFIDENTIAL

EXHIBIT MG-4

EXHIBIT MG-4
E-100, SUB 190

2024 Multi-Value Strategic Transmission Study

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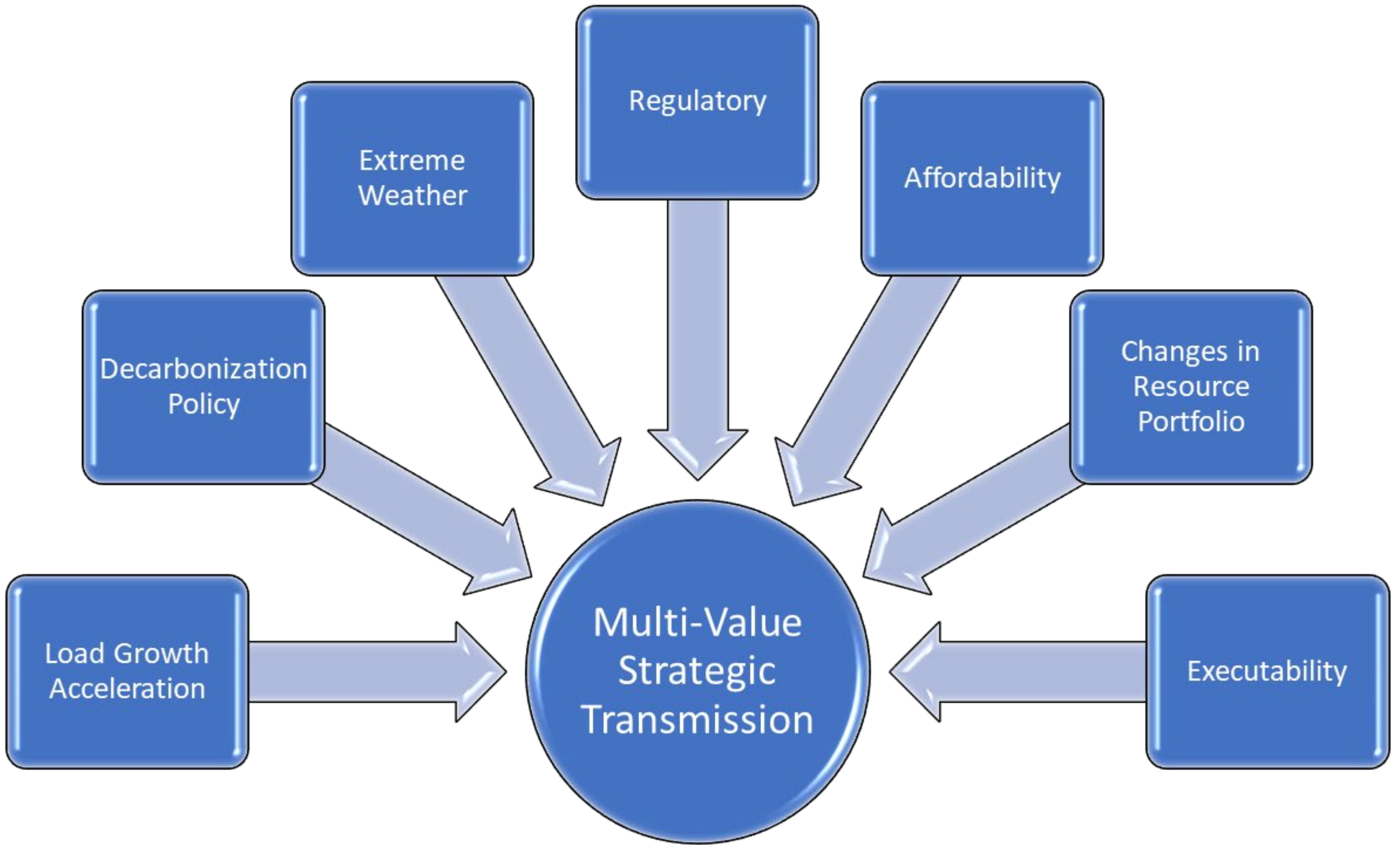
BUILDING A SMARTER ENERGY FUTURE℠

Going Beyond Red-Zone Expansion Plans - Multi-Value Strategic Transmission

- Adopts a forward-looking/ proactive approach
- Scenario-based approach accounts for different possible futures
- Accounts for multiple benefits
- Avoids line-specific assessments and piecemeal planning
- Allows for meaningful stakeholder input



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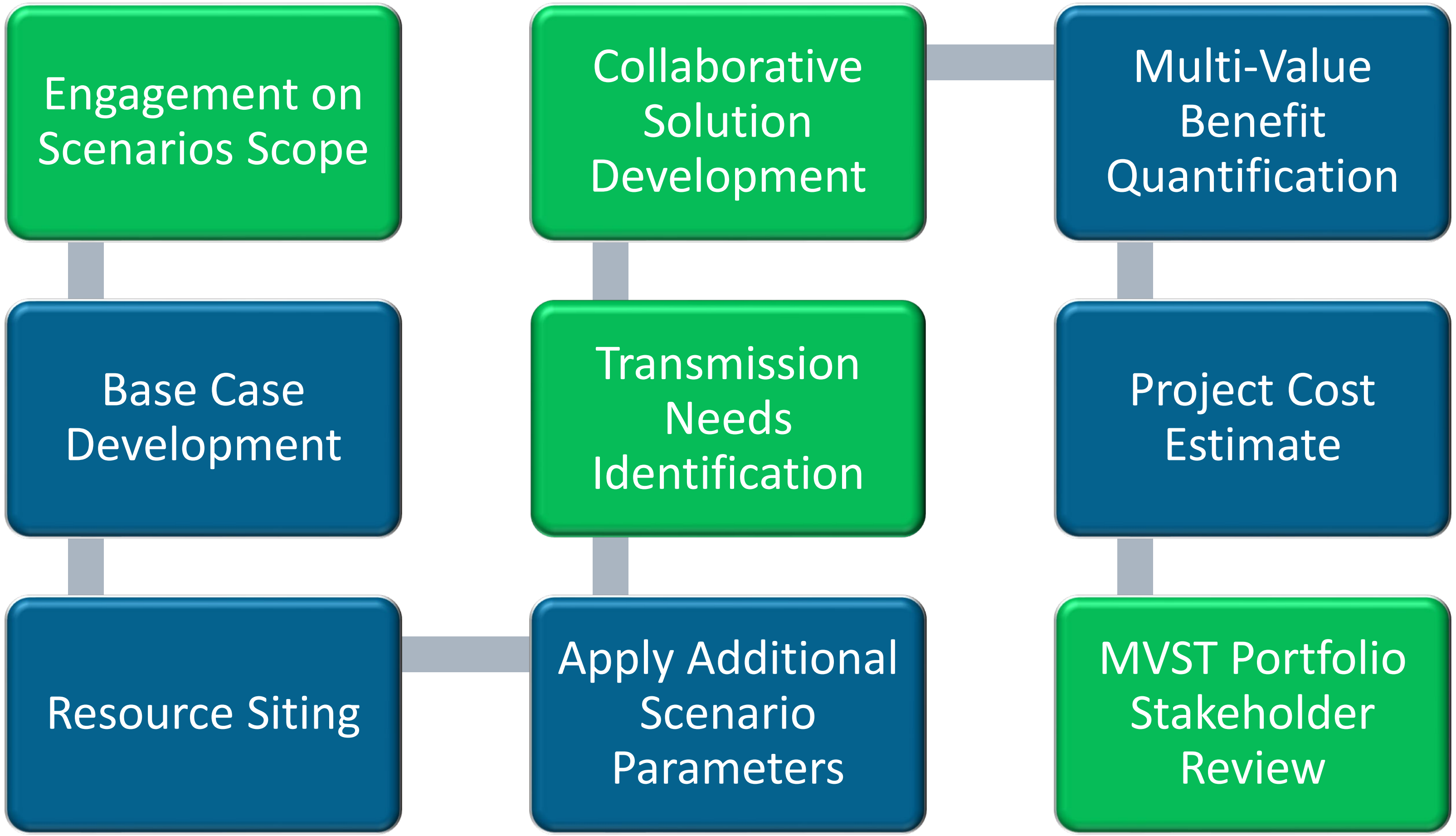
Multi-Value Strategic Transmission Planning – Process Flow

Although stakeholder input can occur at any step of the process, some process steps have been identified as high stakeholder engagement steps.

Requires High Stakeholder Engagement



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Multi-Value Strategic Transmission Planning - Components

Scenario Analysis

- Scenarios developed based on stakeholder input
- Leverages resource planning process in the Carolinas that looks out to 2050
- Evaluate robustness of transmission system across different loads, weather, technology, and fuel forecasts

Solution Development

- Portfolio of solutions to develop the core transmission upgrades needed to address future challenges
- Combination of long-lead time investments that considers potential alternative solutions
- Opportunity for stakeholders to propose solutions for evaluation as part of the MVST portfolio

Multi-Value

- Quantify production, transmission, and customer benefits of proposed portfolio
- Determine that portfolio's business case provides value to stakeholders

Multi-Value Strategic Transmission Planning Scenario Form

STRATEGIC PLANNING SCENARIO PROPOSAL FORM

Date of Proposal: ___________________________

TAG Participant Sponsor(s) of Proposal: _______________________________________

Contact Information for Proposal Sponsors:

Name:_ ____

Phone: ____

Email: ____

Completed forms must be emailed to the CTPC Administrator at least 30 days prior to the Assumptions Meeting

1. GENERAL DESCRIPTION OF PROPOSED STRATEGIC PLANNING SCENARIO
2. PROPOSED MODELS TO BE USED AND REASON FOR INCLUSION
3. PROPOSED ASSUMPTIONS TO BE USED AND WHY
4. PROPOSED DATA SOURCES TO BE USED

   (Include data sources to support assumptions proposed in #3. For example, include proposals such as a reference to an IRP portfolio, a load forecast, an external dataset, etc.)

5. PROPOSED PLANNING HORIZON TO BE USED FOR SCENARIO AND WHY
6. (Optional) SUGGESTED BENEFIT METRICS AND ASSOCIATED METHODOLOGY FOR CONSIDERATION IN EVALUATING POTENTIAL SOLUTIONS

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2024 Public Policy Request 1

Two POIs for 4800 MW of offshore wind

- Recommends two 2400MW POIs of offshore wind injection at the New Bern/Havelock area and at the Jacksonville/Castle Hayne/Folkstone area.

Account for changes in load growth projections in this study

- Duke can add three combined cycle plants in the study with locations selected by the CTPC
- Simple cycle combustion turbines and battery storage may be added as needed to resolve any capacity or generation shortfalls

2024 Public Policy Request 2

Study all standalone solar as energy-only resources using ERIS criteria

The CTPC recommends that we not pursue this scenario as one of the three TAG MVST scenarios since solar developers have stated that they need the certainty of NRIS for project financing purposes. In addition, ERIS for all standalone solar can introduce reliability issues if carried into perpetuity (i.e. network upgrades are not being constructed to provide for NRIS resulting in large curtailments).

2024 Public Policy Request 3

Study the P3 Fall Base resource plan and summarize the difference in the results of the 2024 Public Policy Study and the 2024 Reliability Study, including:

- Which upgrades are common to both the policy study and the reliability study;
- Whether the policy study finds any of the reliability study upgrades are no longer necessary;
- Whether the policy study identifies further upgrades are needed on the same facilities identified for upgrades in the reliability study

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2024 Public Policy Request 4

The fourth Public Policy Study request recommends studying a 1500 MW MISO system purchase with a MISO/PJM; PJM/DEC POR/POD path. This transfer in addition to seven other transfer scenarios are being studied in the Economic Transfer Study and are included in that study scope document.

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2024 Public Policy Request 5

Study 2400 MW of offshore wind from either the Kitty Hawk or Carolina Long Bay wind energy areas injected into different POIs to assess the cost of network upgrades needed to inject the 2400 MW into the DEP system by 2030. The request also recommends estimating the cost of the interconnection facilities and to perform short circuit and stability analysis for interconnecting the resource.

The CTPC does not study interconnection facilities, nor perform short circuit or stability analysis.

2024 MVST Study

With the goal of transitioning the Public Policy Study requests to Multi-Value Strategic Transmission Study scenarios and following the MVST Study process as outlined in the revised Attachment N-1 of the OATT, the CTPC recommends studying the scenarios on the proceeding slides.

The four MVST scenarios will use the P3 Fall Base case resources for the 2034 Summer and 2034/2035 years to be studied with modifications and sensitivities.

2024 MVST Study – Scenario 1

MVST Offshore Wind Scenario - 2400 MW (sensitivity 2400MW injected into different POIs - separate cases)

Potential POIs - New Bern, Jacksonville, Sutton North, Whiteville

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2034 S	2034/35W
Coal	0	-426	0	0	0	-1851	0	-1259	-1318	0	-1371	0	-6225	-6225
Solar	417	440	247	793	1350	1350	1350	1575	1800	1800	1800	1800	12922	14722
Battery	0	0	0	200	820	820	80	20	160	480	480	2040	3060	5100
Onshore Wind	0	0	0	0	0	0	0	300	450	450	450	450	1650	2100
Offshore Wind	0	0	0	0	0	0	0	0	0	800	800	800	1600	2400
Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	0	600
Pumped Storage	0	0	0	0	0	0	0	0	0	0	1834	0	1834	1834
CC	0	0	0	0	0	1360	1360	1360	1360	1360	0	0	6800	6800
CT	0	0	0	0	0	1275	850	0	0	0	0	0	2125	2125

Scenario 1: The base study will assume New Bern for the offshore wind POI. Sensitivity studies will consider Whiteville, Sutton North, and Jacksonville POIs

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2024 MVST Study – Scenario 2

MVST Offshore Wind Scenario - 4800 MW (2- 2400MW OSW resources injected into different POIs)

Potential POIs - New Bern, Jacksonville, Sutton North, Whiteville

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2034 S	2034/35W
Coal	0	-426	0	0	0	-1851	0	-1259	-1318	0	-1371	0	-6225	-6225
Solar	417	440	247	793	1350	1350	1350	1575	1800	1800	1800	1800	12922	14722
Battery	0	0	0	200	820	820	80	20	160	480	480	2040	3060	5100
Onshore Wind	0	0	0	0	0	0	0	300	450	450	450	450	1650	2100
Offshore Wind	0	0	0	0	0	0	0	0	0	1600	1600	1600	3200	4800
Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	0	600
Pumped Storage	0	0	0	0	0	0	0	0	0	0	1834	0	1834	1834
CC	0	0	0	0	0	1360	1360	1360	1360	1360	0	0	6800	6800
CT	0	0	0	0	0	1275	850	0	0	0	0	0	2125	2125

Scenario 2: The base study will assume New Bern and Sutton North for the offshore wind POIs with 2400 MW injected into each POI. Sensitivity studies will consider the following combination of POIs with 2400 MW injected into each POI: New Bern/Whiteville, Whiteville/Jacksonville, and Whiteville/Sutton North.

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2024 MVST Study – Scenario 3

MVST Economic Development Load Scenario with solutions compared with Reliability Case solutions

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2034 S	2034/35W
Coal	0	-426	0	0	0	-1851	0	-1259	-1318	0	-1371	0	-6225	-6225
Solar	417	440	247	793	1350	1350	1350	1575	1800	1800	1800	1800	12922	14722
Battery	0	0	0	200	820	820	80	20	160	480	480	2040	3060	5100
Onshore Wind	0	0	0	0	0	0	0	300	450	450	450	450	1650	2100
Offshore Wind	0	0	0	0	0	0	0	0	0	800	800	800	1600	2400
Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	0	600
Pumped Storage	0	0	0	0	0	0	0	0	0	0	1834	0	1834	1834
CC	0	0	0	0	0	1360	1360	1360	1360	1360	0	0	6800	6800
CT	0	0	0	0	0	1275	850	0	0	0	0	0	2125	2125

Scenario 3: The base study will use the same economic development load assumption as considered in the P3 Fall Base case. Sensitivity studies may include considering a +/- 25% deviation in the economic development load.

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2024 MVST Study – Scenario 4

MVST SC Neighboring System Impact - Model SC Company IRP Resources for Impact Assessment

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2034 S	2034/35W
Coal	0	-426	0	0	0	-1851	0	-1259	-1318	0	-1371	0	-6225	-6225
Solar	417	440	247	793	1350	1350	1350	1575	1800	1800	1800	1800	12922	14722
Battery	0	0	0	200	820	820	80	20	160	480	480	2040	3060	5100
Onshore Wind	0	0	0	0	0	0	0	300	450	450	450	450	1650	2100
Offshore Wind	0	0	0	0	0	0	0	0	0	800	800	800	1600	2400
Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	0	600
Pumped Storage	0	0	0	0	0	0	0	0	0	0	1834	0	1834	1834
CC	0	0	0	0	0	1360	1360	1360	1360	1360	0	0	6800	6800
CT	0	0	0	0	0	1275	850	0	0	0	0	0	2125	2125
Santee Cooper													TBD	TBD
Dominion SC													TBD	TBD

Scenario 4: The base case will consider the projected resource plans for Dominion Energy South Carolina and Santee Cooper to the model to study the potential impacts to the local transmission systems and potential solutions to identified transmission needs.

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Recommended Benefits Assessment

Production Cost Savings

- Includes reduction in annual energy losses
- Includes any congestion and fuel savings

Reliability

- Utilize existing Interruption Cost Estimate "ICE" calculator

Generation Capacity

- Includes reduction in peak losses

Avoided Transmission

- Avoiding or deferring other transmission projects

Asset Life

- Most relevant for 44kV towers that are at end of life but not overloaded

Timeline for 2024 MVST Study

March 22, 2024	April 30, 2024	May 20, 2024	June 20, 2024	November 7, 2024	April 15, 2025
Proposed during TAG meeting to transition Public Policy Requests to MVST Scenarios	Present MVST Scenarios to PPR Submitters and Receive Feedback	Post Draft MVST Study Scope Document to CarolinasTPC.org Website for TAG Review	Discuss MVST Scenarios and Assumptions, Criteria for Studying Scenarios	Review and Discuss MVST Identified Needs	Review Solutions to MVST Identified Needs and Discuss Input on Alternative Solutions

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For Discussion Purposes Only

For Discussion Purposes Only

EXHIBIT MG-5

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please refer to Duke's Response to PSDR 28-2. Between the original August 2023 filing and the January 2024 supplemental filing, the Companies reduced available standalone battery storage in the EnCompass model from 4,400 MW per year to 200 MW in 2027, 500 MW per year in 2028-2029, and 1,000 MW per year in 2030 and beyond. These modifications equate to reductions of 95% in 2027, 89% in 2028-2029, and 77% from 2030 onward. When asked how the new, lower battery storage installation limits were derived, the Companies cited "significant factors… includ[ing] impact to forecast global stationary battery storage equipment and construction services markets, availability of locations on the transmission system requiring relatively low upgrades to facilitate new firm interconnection, cumulative effect on interconnection construction volume." Please respond to the following questions.

a. Please provide any forecasts of global stationary battery storage equipment and construction service markets, and the source of the forecasts, which the Companies used to determine the new battery storage limit. Please explain how the Companies used data from those forecasts to determine the new battery storage availability limits.

b. Please provide any analysis, documentation, or workpapers on transmission locational availability for new firm interconnection that the Companies used to determine the new battery storage limit. Please provide the source of the data and explain how the Companies used these data to determine the new battery storage availability limits.

c. Is the availability of locations on the transmission system requiring relatively low upgrades to facilitate new firm interconnection a greater constraint on the development of battery storage than it is on the development of other generation resources? Why or why not? Please provide any analysis, documentation, or workpapers to substantiate the Companies' response.

d. Please provide a further description of the cumulative effect on interconnection construction volume that the Companies site as a reason to lower the battery storage availability limit. Please provide any analysis, documentation, or workpapers that support this point, the sources of that information, and an explanation of how the Companies used the data to determine the new battery storage availability limits.

e. Does the construction of battery storage impact interconnection construction volume differently than the construction of any other generation resources? If so, please explain.

f. For Portfolio P3 Fall Base, please provide a spreadsheet showing the MW of battery storage economically selected in EnCompass during each year, for each utility. Please indicate, for each year and each utility, whether the amount of storage economically selected is equal to the maximum availability constraint.

Response:

(a): Forecasted size of global battery storage markets was used as one consideration among many to predict what amount of batteries can be procured, constructed, and integrated for the assumed generic cost in each year within the planning horizon. Importantly, the Companies assessed whether their allowable annual additions would constitute a material increase in projected global and US energy storage demand which would thereby drive up cost or challenge the market's ability to supply necessary equipment at all. While multiple internal departments likely viewed several different projections of global market size, one projection that was referenced was Bloomberg NEF's 1H 2023 Energy Storage Market Outlook. A publicly available summary of this report is found at the URL below. In the case of this projection, the Companies integration of standalone battery storage would constitute approximately 1% of global battery market demand and approximately 5% of US demand in that time if they integrated battery storage at the resource model's annual limit from 2027-2030. While several forecasts were referenced by different teams, in the case of the BNEF projection it was judged that the Companies could be assured of their ability to procure this amount of equipment and installation expertise from bankable vendors at relatively stable prices.

The Companies' assessed impact to forecast global stationary storage market was one factor amongst many considered in setting the annual storage selection limit for purposes of SPA modeling. https://about.bnef.com/blog/1h-2023-energy-storage-market-outlook/

(b): With large standalone batteries adding to the number of resources being interconnected in a given year, the ability to enable interconnections of all resources is mutually impactful on the number of resources that can be interconnected in a given year and cumulatively across multiple years.

Limits in early plan years (2027-2029) - depicted in "PS DR 40 (F) - SPA P3 Standalone Battery Projects by Year.xlsx" - are based upon results in 2022 and 2023 DISIS reports based on the estimated timelines in those reports to complete necessary upgrades to interconnect. Those DISIS reports are publicly available on the Duke Energy Carolinas and Duke Energy Progress OASIS sites.

Responder: Michael T. Quinto, Director, IRP Advanced Analytics (c): The assumptions for interconnection limitations for energy storage are described in part b. Low upgrade assumptions generally aligned legacy interconnection study results prior to DISIS that had low interconnection costs. Attachment "PS DR 40 (C) - Battery Network Upgrade Trends.xlsx" shows how network upgrade costs for energy storage have increased as the number and size of projects has increased in the 2022 and 2023 DISIS. Storage is beginning to see the same impacts as other generation resources in being assigned transmission network upgrade costs. The Companies will continue evaluating what network upgrade costs are reasonable to assume for generic energy storage resources.

PS DR 40 (C) -
Battery Network Upgr

(d): See the Companies' responses to Public Staff DR40-1(a) and (b).

(e): See the Companies' responses to Public Staff DR 40-1(a) and (b).

Responder: Sammy Roberts, GM, Transmission Planning and Operations Strategy

(f): lease see the attached file "PS DR 40 (F) - SPA P3 Standalone Battery Projects by Year.xlsx" for the MW of standalone battery storage economically selected in EnCompass during each year For Portfolio P3 Fall Base. Also included in the attached file are the project constraint limits by year for total standalone battery projects, as well as the project constraint limits by year by BA.

The years highlighted, in red, in rows 17-19 indicate years in which the amount of storage economically selected is equal to the maximum availability constraint.

Notably, the updated constraints on BESS included in the SPA modeling to better align with assumed battery availability had relatively limited impacts on model selection of battery additions.

PS DR 40 (F) - SPA
P3 Standalone Battery

Responder: Thomas Beatty, Senior Engineer

Docket E-100, Sub 190
PS DR 40 (C)

Battery Network Upgrades by Cluster - Transmission

Row Labels	Count of Unique ID	Sum of MW	Sum of Network Upgrades ($M)	Average of $/W *note*
Transitional Serial	3	128	$ 6.12	$ 0.05
Transitional Cluster	2	81	$ 3.20	$ 0.04
Surplus	3	75	$ 0.10	$ 0.00
DISIS 2023	11	1848	$ 358.98	$ 0.19
DISIS 2022	5	703	$ 143.92	$ 0.19
Grand Total	**24**	**2835**	**$ 512.32**	**$ 0.14**

note - This is the average $/W for network upgrades. Prior to DISIS clusters, almost all network upgrades were POI network upgrades.

Docket E-100, Sub 190
PS DR 40 (C)

Project Interconnection Desciption	Unique ID	MW	OPCO	Queue	Network Upgrades ($M)	$/W
Camp Lejeune	Q442	11	DEP	Transitional Serial	1.056	$ 0.10
Warsaw	239978	30	DEP	Surplus	0.05	$ 0.00
Monroe	238926	25	DEC	Surplus	0	$ -
Elm City	594134	20	DEP	Surplus	0.05	$ 0.00
Knightdale (Wake)	Q479	100	DEP	Transitional Serial	5.067	$ 0.05
Allen	186466	50	DEC	Transitional Cluster	1.47	$ 0.03
Asheville (fmr. Lake Julian)	Q485	17.25	DEP	Transitional Serial	0	$ -
Craggy	191894	30.5	DEP	Transitional Cluster	1.727	$ 0.06
New Hill	566170	56	DEP	DISIS 2022	3.049	$ 0.05
HF Lee	897163	260	DEP	DISIS 2023	97.873	$ 0.38
Riverbend	563648	115	DEC	DISIS 2022	2.289	$ 0.02
Wilkes	899053	120	DEC	DISIS 2023	13.19	$ 0.11
Harrisburg Tie (External)	567168	197	DEC	DISIS 2022	3.202	$ 0.02
Hodges Tie (External)	568550	197	DEC	DISIS 2022	59.039	$ 0.30
Weatherspoon (External)	898999	199.9	DEP	DISIS 2023	42.122	$ 0.21
Harris 1 (External)	899003	350	DEP	DISIS 2023	47.704	$ 0.14
Harris 2 (External)	899005	199.9	DEP	DISIS 2023	26.101	$ 0.13
Mayo Energy Dome	892419	18.3	DEP	DISIS 2023	2.684	$ 0.15
Spring Hope 2022	565492	138	DEP	DISIS 2022	76.344	$ 0.55
Mayo Battery	893373	150	DEP	DISIS 2023	53.023	$ 0.35
Riverbend (External)	898881	199.9	DEC	DISIS 2023	5.345	$ 0.03
Cliffside 500 kV (External)	898997	199.9	DEC	DISIS 2023	26.049	$ 0.13
Tiger Tie (External)	900491	100	DEC	DISIS 2023	39.713	$ 0.40
Geer Wh (External)	900495	49.9	DEC	DISIS 2023	5.173	$ 0.10

Withdrawn in Gray
Source: Latest Cluster Reports or Facility Studies as of 3/20/2024

Docket No E-100, Sub 190
PS DR 40-1(F)
Portfolio P3 Fall Base Standalone Battery Projects by Year

Total Active Projects	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
DEC 4hr Battery					1	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	6	6	6	6	6	6	6
DEC 6hr Battery																							1	1	1	9	9	9
DEP 4hr Battery					1	1	3	3	3	3	3	3	13	13	13	13	14	19	19	19	25	25	28	28	28	28	28	28
DEP 6hr Battery																				1	5	5	8	10	13	13	13	13
Project Constraint Limits																												
Combined Battery Max Projects					2	5	5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
DEC Max Yearly Battery Projects YYYY					1	3	3	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
DEP Max Yearly Battery Projects YYYY					1	2	2	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Incremental Active Projects																												
DEC 4hr Battery					1	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
DEC 6hr Battery					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	8	0	0
DEP 4hr Battery					1	0	2	0	0	0	0	0	10	0	0	0	1	5	0	0	6	0	3	0	0	0	0	0
DEP 6hr Battery					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	4	0	3	2	3	0	0	0
Total DEC Battery					1	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	8	0	0
Total DEP Battery					1	0	2	0	0	0	0	0	10	0	0	0	1	5	0	1	10	0	6	2	3	0	0	0
Total System Battery					2	3	3	0	0	0	0	0	10	0	0	0	1	5	0	1	10	1	7	2	3	8	0	0

EXHIBIT MG-6

E-100, SUB 190

<u>EXHIBIT MG-6</u>

CONFIDENTIAL

EXHIBIT MG-7

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please confirm that, if asked, Duke's answer in this proceeding would be the same as its response to Sierra Club Data Request 2-1(a) from the ongoing IRP proceeding in South Carolina.

Response:

Response to 33-2: If provided this Sierra Club Data Request 2-1(a) in the CPIRP proceeding, "2-1 Please see the discussion of Generic Transmission Network Upgrade Costs in the Direct Testimony of Dewey S. Roberts II at pages 9-10, and IRP Appendix C at pages 40-41.a. Please provide the assumptions and calculations, in Excel format with formulae intact, used to calculate Generic Transmission Network Upgrade Costs for solar and SPS, onshore wind, and the various tranches of offshore wind shown on page 41 in Appendix C.", the response would be the same.

Responder: Sammy Roberts, GM Transmission Planning & Operations Strategy

EXHIBIT MG-8

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please refer to the slide deck from the Carolinas Transmission Planning Collaborative's TAG Meeting on March 22, 2024 ("TAG Meeting Slide Deck"), available at http://www.nctpc.org/nctpc/document/TAG/2024-03-22/M_Mat/TAG_Meeting_Presentation_for_03-22_2024_FINAL%20NO%20Maps.pdf.

27-2-1 For the planning level estimated costs shown on slide 26, please describe in detail the assumptions that went into those calculations, including the voltage, line miles, and assumed cost of each line upgrade, as well as an itemized list of other equipment upgrades with the assumed cost of each. Please provide this information in editable Excel format with all formulas intact.

27-2-2 Page 39 of Appendix L of the Carolinas Resource Plan states, "The study results and any identified greenfield 230 kV and/or 500 kV transmission line needs will be discussed and included in the NCTPC study report and will be included in future Carolinas Resource Plans along with recommendations for potential transmission expansion projects." Were any greenfield 230-kV and 500-kV upgrades evaluated in the 2023 Public Policy study?

27-2-2-1 If not, please explain why.

27-2-2-2 If so, please describe each of the greenfield 230-kV and 500-kV upgrades that were evaluated. Please also explain whether each was included in the solution set, and if not, the reason why.

Response:

27-2-1: The Companies object to this request as overly broad, unduly burdensome, and not relevant or reasonably calculated to lead to the production of admissible evidence in this CPIRP proceeding to the extent it seeks information that was not used to develop the CPIRP and relates to the Companies' ongoing participation and local transmission planning initiatives through the Carolinas Transmission Planning Collaborative local transmission planning process under Attachment N-1 of the Joint OATT. The CTPC Transmission Advisory Group ("TAG") provides a forum for stakeholders to engage in the CTPC and the Companies' object to using the discovery process in this NCUC Docket for TAG-related questions regarding the Companies transmission planning process. Notwithstanding the foregoing objections, the Companies responds as follows:

the cost estimates were primarily derived from the upgrade costs identified in prior DISIS study for upgrades and RZEP 1.0 project cost estimates applicable to the transmission solutions identified in the 2023 public policy study. For some of the transmission solutions, planning cost estimates were applied.

27-2-2: No.

27-2-2-1: There were no transmission needs identified in the study that warranted a greenfield transmission solution.

Responder: Sammy Roberts, GM, Transmission Planning & Operations Strategy