Attachment 1

Report on Assumptions in Duke Energy May 2022 Carbon Plan,
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Report on Assumptions Used in Duke Energy May 2022 Carbon Plan

Bill Powers, P.E., July 15, 2022

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I. Executive Summary

The May 2022 Carbon Plan prepared by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively "Duke Energy" or "Companies") present four portfolios intended to achieve a 70 percent carbon reduction in electricity production by 2030 (Portfolio 1), by 2032 (Portfolio 2), or by 2034 (Portfolios 3 and 4). These portfolios incorporate varying amounts of combustion turbines (CT), combined cycle gas turbines (CCs), utility-scale solar, utility-scale solar with battery storage, standalone battery storage, onshore and offshore wind power, pumped storage, small modular reactors (SMR), and some net-energy metered (NEM) rooftop solar to achieve carbon reduction targets. The addition of 3,600 MW to 4,000 MW of new gas-fired capacity by 2035 is a common thread in the portfolios. This new gas-fired capacity is presented by the Companies as essential to phase-out coal capacity and to assure reliability with higher levels of solar and wind power. Coal power is not phased-out until 2035.

The solar component of the Carbon Plan presumes large-scale utility solar arrays, 75 MW or greater in capacity, dependent on transmission expansion to be deliverable to demand centers. 5,400 MW of new utility-scale solar is added by 2030 to achieve a 70 percent carbon reduction (Portfolio 1). Rooftop solar, despite being included among "first priority" grid edge technologies in the Carbon Plan to reduce demand, is projected by the Companies to increase in North Carolina by about 240 MW in 2030 and 370 MW in 2035. No portfolio is presented in the Carbon Plan that prioritizes wholesale urban rooftop solar over utility-scale solar to minimize the transmission build-out envisioned in the Carbon Plan.

The Carbon Plan also presents the resource mix needed to achieve full decarbonization by 2050. Large additions of CTs (5,600 MW) and nuclear power (9,300 MW) occur post-2035 as elements to achieve carbon neutrality by 2050.[1] All gas-fired units are presumed to burn 100 percent hydrogen (H_2) post-2050. A core element in the only "70 percent carbon reduction by 2030" portfolio, Portfolio 1, is a substantial increase in gas-fired capacity. Portfolio 1 adds 3,600 MW of new CC and CT capacity by 2030,[2] as a primary mechanism to phase-out coal-fired generation and to reduce greenhouse gas emissions. The Carbon Plan assumes that a solar and battery storage alternative to CTs would be more costly (even in 2050), and that only a limited amount of solar power – even with battery storage – would contribute necessary reliability to the generation mix.

[1] Carbon Plan, App. E, p. 77, Table E-70: Final Resource Additions by Portfolio [MW] for 2035; Table E-71: Final Resource Additions by Portfolio [MW] for 2050. The CT and nuclear capacities added after 2035 are the difference between the CT and nuclear additions by 2035 and by 2050.

[2] Carbon Plan Chapter 3, p. 20, Table 3-3; App. E, p. 77, Table E-69. New CC capacity by 2030 = 2,400 MW; new CT capacity by 2030 = 1,200 MW.

The generation mix to meet the summer peak condition should also be assessed in the Carbon Plan. The Companies use only the winter peak condition as the design basis for the Carbon Plan portfolios. However, the neighboring utilities to the Companies are summer peaking utilities with ample power surpluses to share with the Companies during winter peak conditions. Summer peak loads in DEC and DEP territories in 2021 were significantly higher than the 2020/2021 winter peak loads. It is just as critical for planning purposes that the Carbon Plan portfolios can reliably address the summer peak, the season when the Companies cannot rely on importing large amounts of power from neighboring utility service territories.

This report addresses the following flaws in Duke Energy's Carbon Plan: 1) unnecessary continued use of coal, 2) excessive planning reserve margins driving excessive procurement, 3) faulty generation technology cost assumptions, especially for solar and battery storage, 4) insufficient solar and battery storage in the four portfolios, 5) designing the four portfolios to meet winter peak demand only, 6) excessively high DEC and DEP load forecasts, 7) low rate of net energy-metered (NEM) solar adoption, 8) underestimating the transmission cost adder associated with concentrating utility-scale solar in the transmission-congested "red zone" of the North Carolina and South Carolina eastern border region, 9) ignoring the major environmental impacts of intensive, large-scale solar and transmission line development in the "red zone" on environmental justice communities, and 10) ignoring the cost and environmental benefits of wholesale urban solar as a superior alternative to utility-scale solar and CTs.

Finally, a Distributed Generation (DG) Counter Proposal is presented as an alternative that eliminates coal usage as early as 2024, and displaces the proposed new CC, CT, wind, and nuclear capacity with wholesale urban solar plus storage (SPS) capacity. Wholesale distributed urban SPS is relied on for clean power to maximize resiliency, minimize the transmission build-out, and thereby minimize the cost of to the Companies' customers of achieving carbon-free electricity.

II. Carbon Plan – Over-Reliance on Existing Coal and New Gas, Under-Reliance on New SPS

A. Evolution of the Carbon Plan

The Companies' Carbon Plan presents four portfolios of generation resources to achieve the strategic decarbonization vision the Companies proposed in their 2020 Climate Report. The 2020 Climate Report titled "Achieving a Net Zero Carbon Future" established the goal of net-zero CO_2 emissions from Duke Energy electric generation by 2050.[3] Duke Energy's 2020 Climate

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[3] Duke Energy 2020 Climate Report, *Achieving A Net Zero Carbon Future*, April 2020, p. 1: https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en.

Report, and its net-zero goals, received extensive discussion as part of the 2020 IRPs of DEC and DEP.[4,5] According to Duke Energy at that time, its electric utilities systemwide will achieve the net-zero carbon goal in the following manner:[6]

> The path to net zero by 2050 will require additional coal retirements, significant growth in renewables and energy storage, continued utilization of natural gas, ongoing operation of our nuclear fleet, and advancements in load management programs and rate design (demand side management and energy efficiency).

The Carbon Plan follows the vision presented in the 2020 Climate Report. The Climate Report envisions that over time the natural gas fleet will transition from providing baseload power to a peaking role.[7] It states that Duke Energy's vision "recognize(s) that nuclear and natural gas generation remain essential to transitioning to an affordable and reliable net-zero carbon future."[8] Duke Energy summarizes the role of natural gas in 2050 in this way:[9]

> Even in 2050, natural gas capacity needs to remain on the system to maintain reliability, especially during times of peak electricity demand. However, the mission of the gas fleet will change from supplying 24/7 power today to a peaking and demand-balancing function by 2050. This remaining gas generation is projected to represent 5 percent of 2005 emissions, netted to zero through carbon offset purchases.

The difference in the Carbon Plan is the new proposal to convert all gas-fired units to 100 percent green hydrogen fuel by 2050 and not pursue carbon offset purchases to achieve zero carbon emissions.

B. Insufficient SPS and Standalone Battery Storage

The Companies include a minimal amount of battery storage in the Carbon Plan in the near term. The Carbon Plan target of 350 MW of cumulative operational battery storage by the end

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[4] DEC's 2020 IRP, pp. 131-42.
[5] DEP's 2020 IRP, pp. 132-42.
[6] Duke Energy 2020 Climate Report, p. 1.
[7] Ibid, p. 23. "All natural gas combined-cycle units built in the 2020s are assumed to have a 20-year book life. Beyond 2030, all natural gas additions are assumed to be combustion turbines ('peakers') only."
[8] Ibid, p. 16.
[9] Ibid, p. 28.

of 2027 is very limited in light of the actual U.S. battery storage deployment rate of 3,500 MW per year in 2021.[10,11]

The Companies' claim in the 2020 IRPs that the electric utility industry has little meaningful experience with batteries is unsupported.[12] Utility-scale battery storage has been deployed at scale in the U.S. since 2016.[13] Yet in the Carbon Plan, Duke Energy implies utility-scale battery storage is still transitioning to full commercial status and proposes to add only 350 MW of new battery storage by 2027.[14]

A specific concern expressed by the Companies in their 2020 Climate Report is the ability of the battery storage industry to manufacture the 15,000 MW of additional four-, six- and eight-hour energy storage by 2030 that the Companies say they would need to avoid adding new gas capacity.[15] The Companies have only 13 MW of operational battery storage as of May 2022.[16]

The Companies' concern about the ability of SPS to completely displace new gas capacity is misplaced. The Companies are far behind their peers in adopting battery storage. The California Independent System Operator (CAISO), which includes three major investor-owned utilities, had about 2,500 MW of operational 4-hour battery storage at the end of 2021 and anticipates having 12,000 MW of battery storage by 2025.[17,18] The California Public Utilities Commission has ordered procurement of 1,000 MW of 8-hour battery storage to complement the 4-hour

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[10] Carbon Plan, Appendix E, p. 26. ". . . the Carbon Plan assumes the deployment of approximately 350 MW of nameplate capacity (approximately 110 MW in DEC and 240 MW in DEP) with various storage capacity durations through 2027."

[11] Wood Mackenzie, *US battery storage deployment doubles in a single year*, March 24, 2022: https://www.woodmac.com/news/opinion/us-battery-storage-deployment-doubles-in-a-single-year/.

[12] DEC 2020 IRP, p. 23. "The lack of meaningful industry experience with battery storage resources at this scale presents significant operational considerations that would need to be resolved prior to deployment at such a large scale."

[13] Renewable Energy World, *A Brief History of Utility-Scale Energy Storage*, September 19, 2017: https://www.renewableenergyworld.com/storage/a-brief-history-of-utility-scale-energy-storage/#gref.

[14] App. E, p. 26.

[15] 2020 Climate Report, p. 2.

[16] App. K, p. 2, Table K-1: Energy Storage Systems Located in the Carolinas.

[17] CAISO, *Another side of the battery story*, December 8, 2021: http://www.caiso.com/about/Pages/Blog/Posts/Another-side-of-the-battery-storage-story.aspx.

[18] CAISO, *Storage: An intersection between reliability today and climate goals of tomorrow*, September 14, 2021: http://www.caiso.com/about/Pages/Blog/Posts/Storage-An-intersection-between-reliability-today-and-climate-goals-of-tomorrow.aspx.

battery storage fleet.[19] CAISO has an all-time summer peak load of about 50,000 MW, compared to the Companies' combined summer peak record of 34,079 MW.[20,21]

It is important to point out that the Companies use a different, and misleading, definition of solar plus 4-hour battery storage in the Carbon Plan. The generally accepted industry definition of the number of hours of battery storage relative to the nameplate capacity of the solar array is the number of hours of storage at the capacity rating of that solar array. In other words, if the solar array is rated at 75 MW, then four hours of battery storage is 75 MW x 4 hours = 300 megawatt-hours (MWh).

The Companies do not use this definition. The base case SPS system modeled by the Companies is a 75 MW solar array coupled to 20 MW of battery storage with four hours of storage at 20 MW.[22] This results in the equivalent of about one hour of storage at 75 MW, not four hours of storage at the capacity rating of the solar array.

Grid battery storage capacity is rapidly expanding in the U.S., as shown in Figure 1. Battery storage deployments are expected to reach 7,500 MW per year in 2025, of which about 80 percent is grid battery storage. Figure 2 shows that battery storage deployments in 2021 met the 2021 projection in Figure 1 on the pathway to 7,500 MW per year of overall battery storage additions in 2025. The Companies' battery storage installation target through 2027 is 350 MW, about 1 percent of the projected US installed capacity through 2025 shown in Figure 1.[23]

A 2030 target of 15,000 MW of new battery storage would not require a leap in battery production capability. Other utilities are approaching this target much more quickly than 2030. As noted, California investor-owned utilities are projected to have 12,000 MW of grid-tied battery storage online by 2025. Duke Energy is unlikely to encounter battery storage supply issues if it opts to pursue deployment of 15,000 MW of battery storage by 2030 to avoid the addition of new CC and CT capacity.

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[19] Ibid. "As penetration of storage grows, managing the system will require that storage resources be of longer duration or that significantly more four-hour resources are built. In fact, the California Public Utilities Commission has already ordered the procurement of 1,000 MW of 8-hour (long duration) storage."

[20] CAISO, *California ISO Peak Load History 1998 through 2021*, webpage accessed July 7, 2022: https://www.caiso.com/documents/californiaisopeakloadhistory.pdf. All-time peak = 50,270 MW (2006).

[21] By way of comparison, the Companies combined summer peak record is 34,079 MW. See: Duke Energy press release, *Duke Energy Carolinas customers set summertime record for electricity use*, June 15, 2022.

[22] App. K, p. 7. "For SPS in the Carbon Plan, the Companies originally intended to only model a 4-hour battery that was sized at 25% of the solar facility, but based on this feedback, the Companies included a 2-hour storage option that was paired with solar, sized at 50% of the solar capacity."

[23] The cumulative US installed battery storage capacity through 2025 shown in Figure 1 is approx. 30,000 MW.

Figure 1. U.S. battery storage additions to reach 7,500 MW annually in 2025[24]

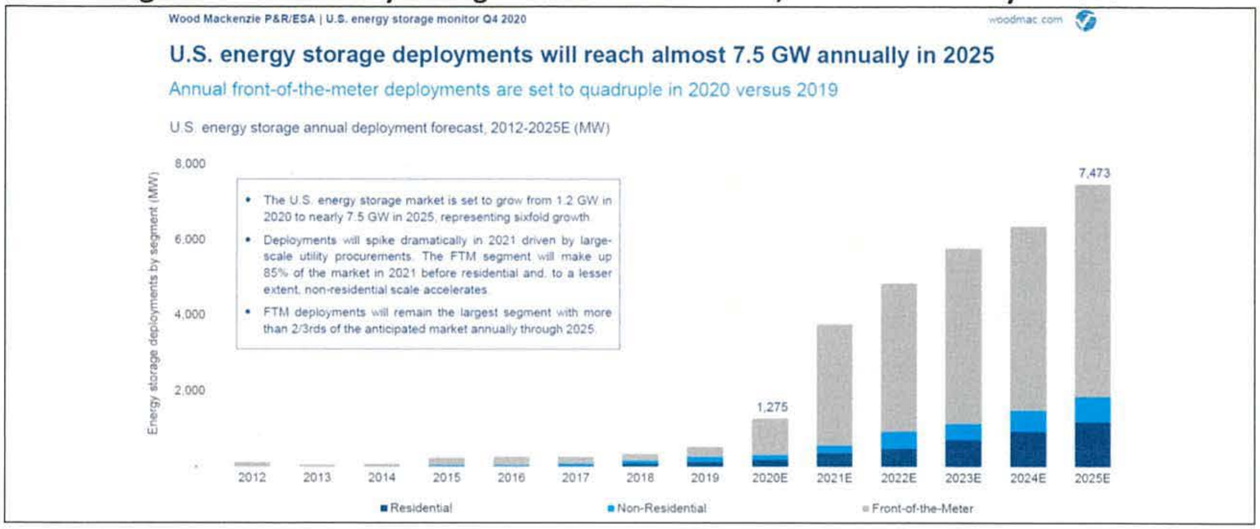
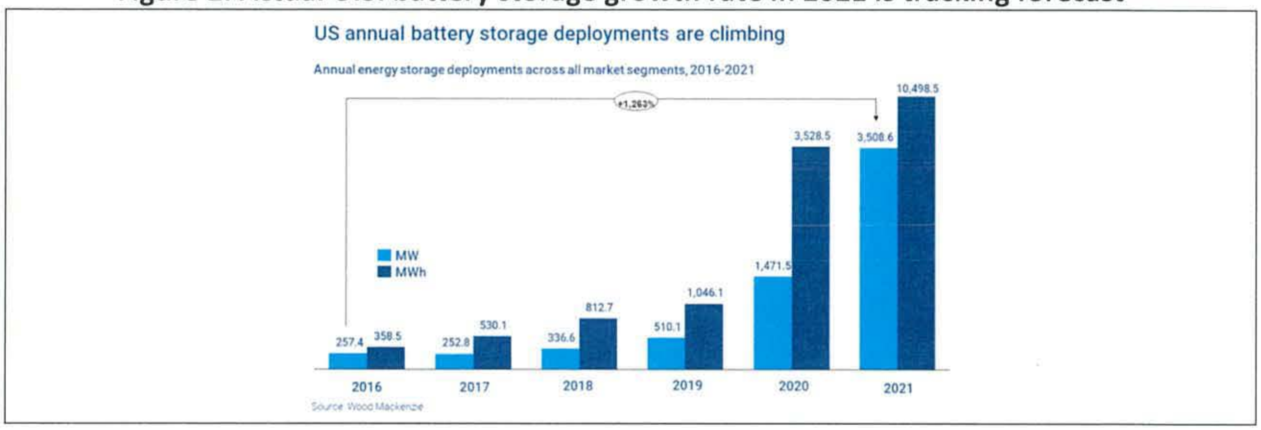


Figure 2. Actual U.S. battery storage growth rate in 2021 is tracking forecast[25]



The lack of sufficient battery storage in the portfolios is a primary reason that the Companies filling the gap with new CC and CT capacity.

C. Carbon Plan Proposes Coal Usage Through 2035, Despite Risks

The Carbon Plan is thorough in its documentation of the multiple risks of continued coal usage. These risks are listed in Table 1. The Carbon Plan makes clear there are ongoing risks in coal supply reliability, coal transportation reliability, and operational risks as these units reach the end of their useful lives.

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[24] Bloomberg Green, *This Is the Dawning of the Age of the Battery*, December 17, 2020: https://www.bloomberg.com/news/articles/2020-12-17/this-is-the-dawning-of-the-age-of-the-battery.

[25] Wood Mackenzie, *US battery storage deployment doubles in a single year*, March 24, 2022: https://www.woodmac.com/news/opinion/us-battery-storage-deployment-doubles-in-a-single-year/. "Overall, 2021 was a record year for grid-scale battery storage deployments with 2.9 GW/9.2 GWh in total, despite over 2 GW being pushed into 2022 and 2023."

Natural gas conversions carried-out by the Companies now allow over 2,600 MW of output on natural gas alone from the coal units that have been converted to dual-fuel units.[26] All DEC coal units, except for Allen Units 1 and 5, which are projected to be retired in early 2024,[27] can operate at partial load or full load on natural gas.

DEP has two coal plants, Mayo (one unit, 713 MW) and Roxboro (four units, 2,462 MW).[28] Mayo is nearly 40 years old and very costly to operate at $90/MWh.[29,30] The average age of the Roxboro units is 50 years.[31] Roxboro is a prime example, due to the age of the coal units there, of the Carbon Plan statement that "*The Companies' remaining coal facilities are nearing the end of their technical and economic life and becoming riskier to operate; thus, retirement is increasingly inevitable.*"

Table 1. Companies' Listing in Carbon Plan of Many Risks of Continued Coal Usage[32]

Introduction	Statement
p. 3	Coal is an increasingly risky fuel source. With more retirements planned for the nation's aging coal fleet, the businesses that supply coal are increasingly distressed, and coal market volatility has increased due to a number of factors, including deteriorated financial health of coal suppliers due to declining domestic demand for coal; uncertainty around proposed, imposed and stayed regulations for power plants; and increasing financing costs for coal producers.
p. 3	These issues are compounded by rail transportation providers' limited and diminishing operational flexibility. This lack of transportation flexibility results in increased difficulty in adapting to changes in scheduling demand needed due to changes in coal's generation burn.
pp. 3-4	Although the Companies continue to manage coal supply assurance risks, the supply chain is expected to further deteriorate over time. These long-term declines in supply uncertainty and operational flexibility ultimately create long-term fuel supply assurance risks for customers.
p. 4	The Companies' remaining coal facilities are nearing the end of their technical and economic life and becoming riskier to operate; thus, retirement is increasingly inevitable.

[26] App. D, p. 2, Table D-1: Coal – Existing Generating Units and Ratings. "Percentage of capacity for maximum standalone natural gas for each unit: Belews Creek 1, Belews Creek 2, Marshall 3, Marshall 4: Up to 50% capable; Cliffside 5, Marshall 1, Marshall 2: Up to 40% capable; Cliffside 6: Up to 100% capable."

[27] App. E, p. 45. "Additionally, the remaining Allen units, units 1 and 5, were modeled to be retired by the beginning of 2024, consistent with transmission project under construction in DEC to enable the retirement of these units."

[28] App. D, p. 2, Table D-1.

[29] DEP, 2020 FERC Form 1, April 15, 2021, p. 403. Mayo, line 35, expenses per net KWh = $0.0897 ($89.70/MWh).

[30] Ibid.

[31] Ibid.

[32] Carbon Plan, Chapter 1 – Introduction, pp. 2-4.

p. 2	Since 2010, DEP and DEC, collectively, have retired approximately 4,400 MW of aging, inefficient coal-fired generation, consisting of 35 units, and converted approximately 3,150 MW of coal capacity, consisting of eight units, such that they can use natural gas as a fuel.

Recommendation: Operate the DEC coal units on natural gas only beginning in 2024, to produce a minimum of 2,600 MW.[33]

D. Proposed Expansion of Gas-Fired Units Despite Fuel, Price, and Carbon Risks

The Carbon Plan acknowledges significant natural gas price risk due to potentially insufficient firm natural gas pipeline capacity to supply the proposed new gas-fired capacity. The Companies address this risk in a sensitivity analysis by displacing CC capacity with battery storage and CTs. There is no mention of carbon risk if the assumption that all gas units will burn 100 percent H_2 by 2050 proves to be incorrect. The Carbon Plan statements about the risks associated with continued natural gas usage are provided in Table. 2.

Methane is not mentioned in the Carbon Plan. Methane is a much stronger greenhouse gas than CO_2. However, there is no mention in the Carbon Plan of upstream methane emissions from the production of natural gas and the impact of those methane emissions on climate.

Table 2. Companies' statements in Carbon Plan of risks of reliance on natural gas

Source	Statement
Chp. 2, p. 4	Finally, as part of the sensitivity analysis discussed in Chapter 3 (Portfolios) and in Appendix E (Quantitative Analysis), all portfolios were also analyzed under an alternative fuel supply sensitivity that examined how the portfolios would change if future access to a limited amount of Appalachian gas supply does not materialize.
Chp. 2, p. 17	Limited Appalachian gas supply (limit of two new CCs up to 2,400 MW)
App. E, p. 31	In the alternate fuel supply sensitivity, natural gas supply is assumed to be more limited and therefore the Companies limit the selection of CCs to a single new CC unit. Additionally in this sensitivity, the assumption for generic CC is a 2x1 F-Class CC with dual fuel capabilities ("CC-F"), operating on both natural gas and ULSD (diesel).
App. E, p. 32	In the alternate fuel supply sensitivity, with limits on natural gas supply, the new CC is assumed to operate on ULSD in potentially natural gas limited periods, responsive to supply constraints and price volatility, and on natural gas the remainder of the year when supply is less limited.

[33] App. E, p. 47, Table E-46: Coal Unit Characteristics Impacting Continued Operation Costs, Note 2. Cliffside Unit 5 and Marshall Units 1 and 2 cannot fire natural gas when Cliffside 6 and Marshall 3 and 4 are fully utilizing their natural gas capability.

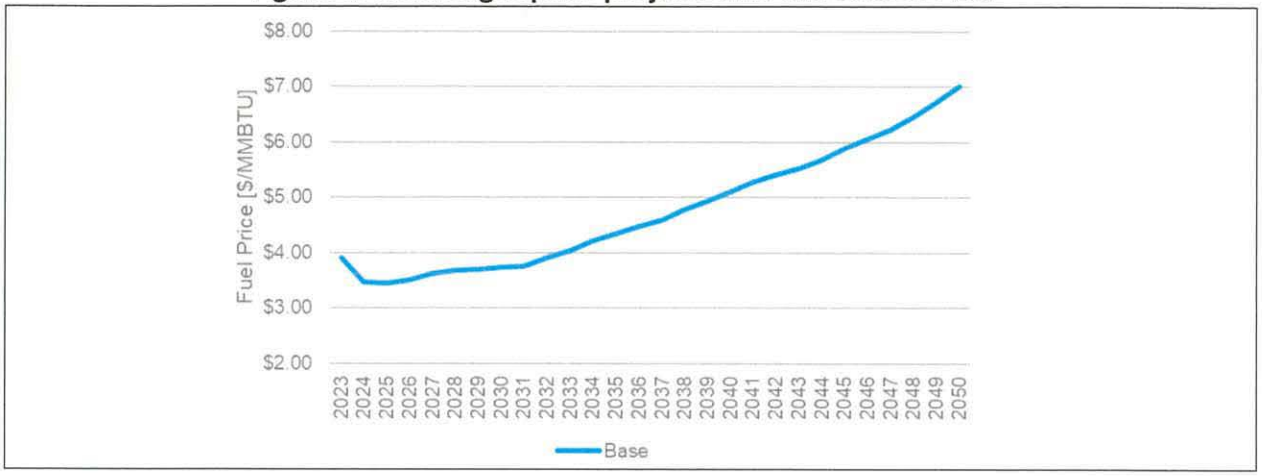
App. E, p. 41	Because there is uncertainty on how incremental natural gas supply to the DEC and DEP service territories will materialize, the Companies have developed a base fuel supply assumption and an alternate fuel supply sensitivity for the Carbon Plan.
App. E, p. 42	The Companies also developed an alternate fuel supply sensitivity, which assumes that DEC and DEP do not receive access to any Appalachian gas via firm transportation capacity . . . this sensitivity limits operations of some generation units to coal and ULSD (diesel fuel) during times of potentially limited supply and price volatility.
App. E, p. 85	Effect of natural gas supply constraint on P1 in 2030: +1,800 MW batteries, -1,600 MW of CCs, +1,000 MW of CTs.
App. E, p. 89	Because the lack of fuel supply diversity in this sensitivity, natural gas delivered to the Carolinas continues to see price volatility . . .

Natural gas price volatility has been an inherent feature of the natural gas market, as shown in Figure 3. Natural gas prices have been especially volatile in 2022, with the May 2022 Henry Hub price over $8 per million Btu. Western Europe has become a high demand, priority delivery point for U.S. natural gas in the form of LNG in the wake of the Ukraine war, driving increases in U.S. natural gas prices. Yet the Carbon Plan assumes a low base price for natural gas, under $4/MMBtu through 2032 rising to $5/MMBtu in 2040, as shown in Figure 4.

Figure 3. Historic Henry Hub benchmark natural gas price volatility[34]

[34] EIA, Natural Gas, accessed July 3, 2022: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

Figure 4. Natural gas price projection in the Carbon Plan[35]



The price of natural gas is volatile over time, as shown in Figure 1. In contrast, there is no price volatility over time in the price (free) or availability of solar power.

E. Non-CO_2 Greenhouse Gas Emissions Are A Non-Issue If New CCs and CTs Are Eliminated from the Carbon Plan

HB 951 specifies reduction of carbon dioxide (CO_2) emissions and ignores other greenhouse gases. As a result, NCUC addressed only CO_2 when it instructed Duke Energy to file a Carbon Plan. Natural gas is 70 to 90 percent methane.[36] Non-CO_2 greenhouse gases, which include methane, are responsible for about half of greenhouse gas impacts.[37] Methane is more than 80 times as potent a greenhouse gas as CO_2 over its first 20 years in the atmosphere, and accounts for about 30 percent of global warming.[38] New climate research is increasingly pointing to the critical need to reduce not just CO_2 but also short-lived climate pollutants such as methane.[39,40]

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[35] App. E, p. 40, Figure E-6: Base Henry Hub Natural Gas Price Forecast [$/MMBtu].

[36] Yale – Climate Change Communication, *Should it be called "natural gas" or "methane"?*, December 1, 2020: https://climatecommunication.yale.edu/publications/should-it-be-called-natural-gas-or-methane/.

[37] PNAS, *Mitigating climate disruption in time: A self-consistent approach for avoiding both near-term and long-term global warming*, May 2022, pp. 1-2: https://www.pnas.org/doi/epdf/10.1073/pnas.2123536119. "Many publications and reports by scientific agencies (24–32) highlighted the role of non-CO2 for rapid near-term climate mitigation, specifically short-lived climate pollutants (SLCPs)—methane (CH4), BC, hydrofluorocarbons (HFCs), and tropospheric ozone (O3) — but these have not captured the attention of global mitigation actions, which still focuses largely on CO2 emissions."

[38] United Nations Environment Programme, *Methane emissions are driving climate change. Here's how to reduce them*, August 20, 2021: https://www.unep.org/news-and-stories/story/methane-emissions-are-driving-climate-change-heres-how-reduce-them.

[39] *Mitigating climate disruption in time, op. cit.*, "deeper CO2 reductions this decade do not replace the need for methane and other SLCP reductions to slow warming in the near term."

[40] Nature Energy, *The expansion of natural gas infrastructure puts energy transitions at risk. Nature Energy* (July 2022), https://www.nature.com/articles/s41560-022-01060-3. ""We propose five ways to avoid common shortcomings for countries that are developing strategies for greenhouse gas reduction: manage methane

Methane reduction is not an explicit objective of the Companies' Carbon Plan. However, eliminating the addition of new natural gas-fired generation in the Carbon Plan would address both the CO_2 emitted by combusting methane and reduce the upstream methane emissions that occur prior to the methane being combusted in CCs and CTs.

Methane emissions prior to combustion in the gas turbine are a major concern from a greenhouse gas reduction perspective. Some percentage of methane leaks into the atmosphere during well drilling, storage, compression, and transport. Methane is also vented as a routine aspect of pipeline maintenance operations.[41]

Methane has a worse climate impact than coal if more than about 3 percent is lost to leakage upstream of the combustion source.[42,43] A research study published in March 2022 indicates 9.4 percent of gross gas production in the Permian Basin of New Mexico is being emitted to the atmosphere unburned from extraction and transportation activities.[44]

F. Critical Capital Cost Assumptions In the Carbon Plan Are Unknown

The Carbon Plan portfolios are primarily the result of: 1) new capacity (generation mix) modeling, to demonstrate that the chosen generation mix provides sufficient reliable power at the winter peak, and 2) production cost modeling, to determine the absolute and relative cost of each portfolio.[45] The four portfolios contain different mixes of generation assets to achieve specified carbon reduction targets by 2030 (Portfolio 1 only), 2035, and 2050.[46]

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emissions of the entire natural gas value chain, revise assumptions of scenario analyses with new research insights on greenhouse gas emissions related to natural gas, replace the 'bridge' narrative with unambiguous decarbonization criteria, avoid additional natural gas lock-ins and methane leakage, and take climate-related risks in energy infrastructure planning seriously...Meeting the Paris Agreement and longer-term climate mitigation targets inevitably implies a fossil natural gas exit. The earlier such a gas exit is planned for, the more of the emission budget remains for those sectors that are harder to decarbonize."

[41] Energy News Network, *Gas pipeline venting mishap reveals lack of guidelines for alerting public*, October 13, 2016: https://energynews.us/2016/10/13/gas-pipeline-venting-mishap-reveals-lack-of-guidelines-for-alerting-public/.

[42] Bloomberg, *As Gas Prices Soar, Nobody Knows How Much Methane Is Leaking*, May 3, 2022: https://www.bloomberg.com/features/2022-methane-leaks-natural-gas-energy-emissions-data/.

[43] International Energy Agency, World Energy Outlook 2017, p. 417, https://iea.blob.core.windows.net/assets/4a50d774-5e8c-457e-bcc9-513357f9b2fb/World_Energy_Outlook_2017.pdf.

[44] Environmental Science & Technology, *Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey*, March 2022: https://pubs.acs.org/doi/10.1021/acs.est.1c06458.

[45] Chapter 2, p. 4.

[46] Carolinas Carbon Plan, Chapter 2 – Methodology, p. 4. "The Companies used the EnCompass capacity expansion and production cost simulation software package ("EnCompass") as the primary modeling tool for the development and analysis of the Carbon Plan portfolios." The Carbon Plan also projects a post-2035 generation additions to achieve full decarbonization by 2050.

A fundamental input to the production cost model used by the Companies to compare the cost of the different portfolios is the capital cost of the generation technologies. However, nowhere in the Carbon Plan does Duke Energy explicitly identify the capital cost assumptions, in dollars per kilowatt ($/kW) of capacity, used for the generation technologies included in the Carbon Plan.

Duke Energy includes hundreds of tables and figures between the Carbon Plan and the twenty-four separate Carbon Plan appendices and attachments. One of those tables does list the forecast capital cost decline rate for each generation technology included in the Carbon Plan from 2022 to 2050.[47] However, there is no table identifying the initial 2022 capital cost assumptions that the capital cost decline rates apply to.

The lack of a summary table in the Carbon Plan with all of the initial capital costs used for the generation technologies included in the portfolios is a shortcoming. Table 3 lists all the sources of capital cost information that Duke Energy references in the Carbon Plan for different generation technologies included in the Carbon Plan portfolios. Use of undisclosed "proprietary third-party engineering estimates" for generation technologies that play major roles in the Carbon Plan portfolios, including CTs, CCs, wind power, new nuclear, and pumped storage, is a major deficiency. Solar and battery storage are the only generation technologies where Duke Energy provides a publicly traceable reference for the capital cost, which is the "NREL 2021 Annual Technology Baseline moderate scenario."

The NREL 2021 Annual Technology Baseline (ATB) moderate scenario is a reasonable capital cost assumption for solar and battery storage. However, the reasonableness of Duke Energy's inclusion of greater or lesser amounts of CT and CC capacity in the Carbon Plan portfolios cannot be assessed because the CT and CC capital costs are not provided. This same deficiency applies to new nuclear, wind, and pumped storage.

Table 3. Duke Energy capital cost references cited in the Carolinas Carbon Plan

Generation Technology	Description
Solar & solar plus storage, Chp. 2, p. 18	The Companies based solar and solar paired with storage costs on proprietary third-party engineering estimates specific to the Carolinas, which are slightly lower than the NREL 2021 Annual Technology Baseline ("ATB") moderate scenario cost assumptions.
Battery storage, Chp. 2, p. 20	Battery storage costs were based on proprietary third-party engineering estimates specific to the Carolinas and are within 1% of the NREL 2021 ATB moderate scenario cost assumptions. Bad Creek II Pumped Storage Hydro cost was based on proprietary third-party engineering estimates.

[47] Ibid, Appendix H - Screening of Generation Alternatives, Table H-2: Forecast Factor Table by Technology

New nuclear, Chp. 2, p. 21	Advanced nuclear reactor costs were based on EPRI's cost and performance estimate and proprietary third-party engineering estimates.
Wind, Chp. 2, p. 22	Wind technology costs are based on proprietary third-party engineering estimates specific to the Carolinas.
CT/CC, Chp. 2, p. 24	CT and CC costs are based on proprietary third-party engineering estimates specific to the Carolinas.
Storage/CC mix, Chp. 2, p. 26.	The detailed production cost step in EnCompass also allows for verification of, and adjustments to, initial storage and CT levels from the capacity expansion model to ensure least-cost optimization while maintaining system reliability and meeting carbon reduction targets.
Hydrogen-fueled CT/CC, Chp. 2, p. 25.	Hydrogen-fueled turbines are a developing technology, and cost estimates for retrofits and new hydrogen capable units are not available from original equipment manufacturers ("OEMs") at this time. Duke Energy developed cost estimates for use in the Carbon Plan modeling based on discussions with third-party OEMs.
Transmission, App. E, p. 38	Transmission cost estimates were derived for network transmission upgrades where prior studies had indicated the path and likely transmission needs for interconnecting a specific supply-side resource. Otherwise, prior studies or similar analysis for a greenfield generator such as a CC generator was used to establish a proxy cost for network transmission upgrades.
Capital cost decline rate, App. H, p. 8	Duke Energy developed a capital cost forecast with support from a third party to project the costs of all resource technologies passing the technical screening phase. The Technology Forecast Factors were sourced from the EIA Annual Energy Outlook 2021, which provides cost projections for various technologies through the planning period as an input to the National Energy Modeling System ("NEMS") utilized by the EIA for the AEO.

The lack of any explicit CT and CC $/kW capital cost information in the Carbon Plan is a major flaw from the standpoint of assessing the validity of the portfolios.

In the Companies earlier iteration of a climate action plan, the 2020 Climate Report, the Companies identify capital cost assumptions of $650/kW for CCs and $550/kW for CTs.[48] The inclusion of specific capital cost estimates for the CTs and CCs allowed other parties to corroborate the accuracy of those estimates against recent CC and CT projects built by the Companies. No specific CT or CC $/kW capital cost assumptions were included in the public versions of the 2020 DEC and DEP IRPs.

[48] 2020 Climate Report, p. 24: Combustion Turbines – $550/kilowatt (kW) (represents multi-unit site); Combined Cycle – $650/kW (represents 2x1 advanced class).

The Companies have actual recent experience building both CC and CT projects. The capital costs of these CC and CT projects are known. These are the CC and CT capital costs that should be used in the Carbon Plan modeling and not hypothetical, generic values.

The actual capital cost of the 560 MW Asheville combined cycle plant, which came online in 2020, was $817 million.[49] This is equivalent to a unit CC cost of about $1,460/kW,[50] over double Duke Energy's assumed CC cost of $650/kW in its 2020 Climate Report. The same NREL database that Duke Energy references as the basis for its solar and battery storage cost in the Carbon Plan identifies a generic mid-range capital cost for CC plants of $1,044/kW in 2021, declining only slightly to $977/kW in 2035.[51] Presumably the Companies did not use this same NREL 2021 Annual Technology Baseline (ATB) moderate scenario data for the CC capital cost, as they did for solar and battery storage, because the value was inconveniently high.

The capital cost of the 402 MW Lincoln CT, the most recent example of a CT built and owned by Duke Energy, is not public information and was filed with the NCUC under seal.[52] For this reason, Powers Engineering assumes the CC cost multiplier of the Asheville CC plant, which is more than double the generic CC cost assumption used by the Companies, also applies to new CTs. This is equivalent to a unit CT cost of approximately $1,250/kW,[53] compared to Duke Energy's assumed CT cost of $550/kW in the 2020 Climate Report. Also, the NREL ATB database referenced by Duke Energy identifies a generic mid-range capital cost for CTs of $919/kW in 2021, declining to $823/kW in 2035.[54]

The Companies rely on the NREL ATB database for capital cost values for some generation sources, but opt to develop distinct proprietary values for the CCs and CTs in the Carbon Plan. This choice by the Companies implies that they found the NREL ATB CC and CT capital costs to be too high to support the CC and CT capacity the Companies desired in the Carbon Plan portfolios.

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[49] Duke Energy News Center, *Duke Energy Progress customers receiving 560 megawatts of cleaner energy from new natural gas power plant in North Carolina*, July 22, 2020: https://news.duke-energy.com/releases/duke-energy-progress-customers-receiving-560-megawatts-of-cleaner-energy-from-new-natural-gas-power-plant-in-north-carolina.

[50] $817,000,000 ÷ 560,000 kW = $1,459/kW.

[51] NREL, Electricity Annual Technology Baseline (ATB) 2021, "Fossil Energy Technologies" tab, Natural Gas FE CT Ave CF, webpage accessed July 2, 2022. https://atb.nrel.gov/electricity/2021/fossil_energy_technologies.

[52] *See* NCUC Docket No. E-7 Sub 1134.

[53] Adjusted combustion turbine unit cost: ($1,460/kW ÷ $650/kW) x $550/kW = $1,235/kW.

[54] NREL, Electricity Annual Technology Baseline (ATB) 2021, "Fossil Energy Technologies" tab, Natural Gas FE CT Ave CF, webpage accessed July 2, 2022. https://atb.nrel.gov/electricity/2021/fossil_energy_technologies.

Recommendation: The NCUC should direct the Companies to use the final capital cost of the Lincoln 402 MW CT and the Asheville 560 MW CC as the base case 2022 capital cost assumptions for CTs and CCs in the Carbon Plan.

III. Competing Utilities Identify SPS as Superior to Other Generation Options

Other investor-owned utilities operating in Duke Energy markets view solar plus battery storage as a superior alternative to CTs for cost reasons alone. NextEra Energy, parent company of Florida Power & Light (FPL),[55] states that "batteries are now more economic than gas-fired peakers (CTs), even at today's natural gas prices."[56] FPL is the largest investor-owned utility in Florida.[57] NextEra Energy also forecasts the production cost of solar plus battery storage is less than the production cost of an existing CT.[58]

FPL is far larger than Duke Energy Florida, with 114,000 MWh of retail sales in 2020 compared to 39,000 MWh for Duke Energy Florida.[59] By way of comparison, the combined DEC and DEP retail sales in North Carolina were 92,000 MWh in 2020.[60]

NextEra Energy includes its forecast of late 2020s production costs for selected generation technologies in its June 2022 Investor Conference 2022 presentation.[61] These production costs are summarized in Table 4.

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[55] Companies owned by NextEra Energy: https://www.nexteraenergy.com/company/subsidiaries.html.

[56] GreenTech Media, *NextEra looks to spend $1B on energy storage in 2021*, April 22, 2020.

[57] EIA, State Electricity Profile – Florida, (xls attachment, Table 3:

[58] NextEra Energy, Investor Conference 2022, PowerPoint, June 14, 2022, p. 26: https://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/news-and-events/events-and-presentations/2022/06-14-2022/June%202022%20Investor%20Presentation_Website_vF.pdf.

[59] EIA, *Florida Electricity Profile 2020*, Full Data Tables, 1-17, Table 3: Top five retailers of electricity, with end use sectors (xls spreadsheets), November 4, 2021: https://www.eia.gov/electricity/state/florida/. 2020 FPL retail sales = 113,663,998 MWh; 2020 Duke Energy Florida retail sales = 39,230,213 MWh.

[60] EIA, *North Carolina Electricity Profile 2020*, Full Data Tables, 1-17, Table 3: Top five retailers of electricity, with end use sectors (xls spreadsheets), November 4, 2021: https://www.eia.gov/electricity/state/northcarolina/. 2020 DEC retail sales = 55,703,047 MWh; 2020 DEP retail sales = 36,297,536 MWh. Total 2020 DEC + DEP = 92,000,583 MWh.

[61] NextEra Energy, Investor Conference 2022, PowerPoint, June 14, 2022, p. 26.

Table 4. NextEra Energy late 2020s production costs for selected generation technologies

Generation technology	Production cost, $/MWh
Solar with 4-hour battery storage*	30 - 37
Existing natural gas-fired	35 - 47
Existing nuclear	34 - 49
Existing coal-fired	43 - 74
New natural gas CC	56 - 69

*) Assumes a 4-hour battery to achieve roughly equivalent reliability during peak hours for comparison with dispatchable generation sources.

The relative cost relationships shown in Table 4 hold true for the Companies' units as well. For example, the CT power plant with the lowest production cost among the Companies' CTs is the 978 MW Rockingham plant, with a production cost of $42 per MWh in 2019.[62] This contrasts with the production cost of DEP's coal-only Mayo and Roxboro plants, which range from $54/MWh to $90/MWh.[63] There are CTs in the Companies CT fleets that can operate at lower-cost than DEP's remaining coal units and are a lower-cost power production option to those coal units.

IV. The Companies Places Artificial Constraints on SPS, Artificially Lowering the Reliability Value

Duke Energy claims in its 2022 Carbon Plan and its 2020 Climate Report that above a certain point SPS additions have diminishing reliability value and ultimately become uneconomic for carbon reduction.[64]

The Carbon Plan relies on resources used to compile the 2020 DEC and DEP IRPs. One study appearing in both the 2020 Climate Report and the 2020 DEC and DEP IRPs, a January 2020 NREL study of the impacts of integrating increasing levels of solar and battery storage, is specific to DEC and DEP territories in North Carolina and South Carolina. The NREL study was paid for by Duke Energy.[65]

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[62] Ibid, p. 403.3 (Rockingham), line 35, $0.043/kWh ($42/MWh).

[63] DEP, 2020 FERC Form 1, April 15, 2021, p. 402.1 (Roxboro, $0.0538/kWh) and p. 403 (Mayo, $0.0897/kWh).

[64] Duke Energy 2020 Climate Report, p. 27: https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf.

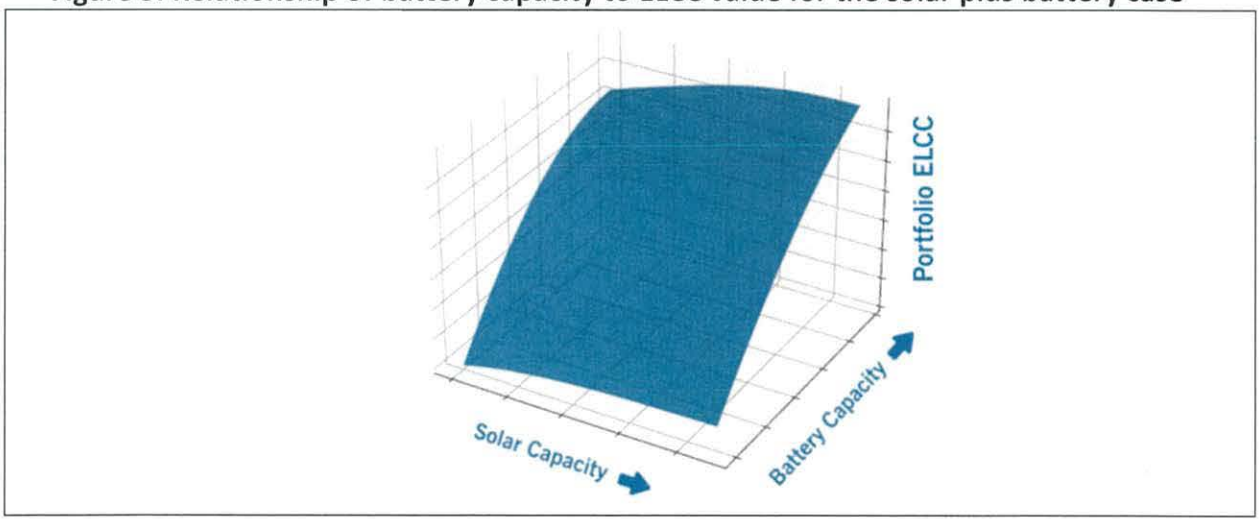
[65] NREL, *Carbon-Free Resource Integration Study*, Technical Report NREL/TP-5D00-74337, January 2020, pdf p. 3. "NOTICE - This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by Duke Energy. The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government."

The NREL report, due to the restrictions placed on the scenarios that are studied, gives the erroneous impression that the amount of solar power that can be productively utilized in DEC and DEP service territories, even with battery storage, is quite limited. That conclusion is exclusively an artifact of the restrictions placed on the scope of the twelve scenarios studied by NREL at Duke Energy's instruction. The NREL report comes with a disclaimer: "The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government."[66] In this case, Duke Energy benefits from the prestige of a national laboratory report, while defining the terms and scope of the study.

The Companies do not directly reference this 2020 NREL study in the Carbon Plan, but do adopt in the Carbon Plan the same undersized storage assumption used in the NREL study to make the incorrect claim that, above a certain relatively modest amount of SPS, the SPS alternative provides little additional reliable capacity.

This result is achieved by assuming the solar with battery storage alternative only has about one hour of battery storage in the Electric Load Carrying Capability (ELCC) analysis, and by assuming winter peak conditions when little solar power is available. The ELCC is the "capacity value of a resource and can be thought of as a measure of the reliable capacity contribution of a resource being added to an existing generation portfolio."[67] The more battery storage that is added to the solar resource, the higher the ELCC value, as shown in Figure 5.

Figure 5. Relationship of battery capacity to ELCC value for the solar plus battery case [68]



[66] Ibid.

[67] Carbon Plan, Appendix E, p. 11.

[68] Ibid, Appendix E, Figure E-5: Depiction of a Solar and Storage ELCC Surface, p. 12.

The utility-scale solar plus battery building block in the Carbon Plan ELCC analysis is a 75 MW solar array coupled to 20 MW of battery storage with 80 MWh of storage capacity.[69] This is approximately one hour of storage at the solar array design capacity of 75 MW.[70] Not surprisingly, this inadequate amount of storage results in the solar plus storage alternative having a low ELCC.[71]

On a clear summer day, a 75 MW solar array may produce as much as 600 MWh of solar power.[72] In this case, a solar array with battery storage designed to absorb six hours of solar output at the design output of the 75 MW solar array,[73] or 450 MWh, would assure the solar output is fully deliverable with an ELCC at or near 100 percent.

The Companies confirm this in their assessment of the ELCC of standalone battery storage installations. Unlike the badly undersized storage capacity in the two solar plus battery profiles,[74] the Companies assume that standalone battery storage will be capable of discharging 4-hours, 6-hours, or 8-hours of power at rated capacity.[75] As a result, these conservatively designed, relatively long-duration standalone battery installations have high ELCCs.[76]

The Companies ELCC modeling indicates that as more-and-more battery storage capacity is added, longer-and-longer battery durations are needed to maintain high ELCC values. That is what should be modeled. What should not be modeled is a single solar plus battery storage profile with a badly undersized battery storage component. The predictable result is that solar plus battery storage will provide little contribution to reliable capacity, and therefore must be supplemented with other resources like CTs.

The 2020 NREL study, paid for by the Companies, includes an analysis of balancing solar and load for typical days during different seasons and minimum and peak net load days. The intent of the study is to assist Duke Energy to understand (solar) curtailment issues during periods of

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[69] Carbon Plan, Appendix E, Table E-29: Solar paired with Storage (50% Battery Ratio) Modeling Assumptions (32.4% solar capacity factor), and Table E-30: Table E-30: Solar paired with Storage (25% Battery Ratio) Modeling Assumptions (33.5% solar capacity factor), p. 29.

[70] The Companies use what is effectively a sleigh-of-hand to assert two solar plus storage profiles include either 2-hour or 4-hour battery storage. This is achieved by setting the discharge capacity of the battery storage well below the 75 MW capacity of the solar array. In Option 1, the Companies set the discharge capacity of storage at 20 MW for 4-hours (80 MWh total). In Option 2, the Companies set the discharge capacity of storage at 40 MW for 2-hours (80 MWh total). The bottom line in both options is that the duration of the total storage capacity (80 MWh) is about 1-hour relative to the design capacity of the 75 MW solar array.

[71] Appendix E, p. 14, Table E-6: DEC Winter Solar Paired with Storage Incremental ELCC Values; Table E-7: DEP Winter Solar Paired with Storage Incremental ELCC Values.

[72] 75 MW x 24 hr x 0.324 = 583 MWh.

[73] 75 MW x 6 hr = 450 MWh.

[74] Carbon Plan, Chapter 2, p. 18, Table 2-8: Solar Paired with Battery Storage, Plan Modeling Options.

[75] Appendix E, p. 33, Table E-36: Standalone Battery Modeling Assumptions.

[76] Ibid, Table E-4: DEC Standalone Storage Incremental ELCC Values, p. 13.

low load with high penetrations of solar energy. DEC and DEP have a high percentage of inflexible nuclear generation, which operates at 100 percent capacity round-the-clock. This leaves relatively limited load that is "available" to be met by solar power on days, generally in the spring and fall, with light demand. On the other hand, the 2,100 MW of existing DEC pumped storage does increase the flexibility of the DEC system to absorb solar power.

NREL evaluated twelve scenarios with various levels of solar capacity, ranging from 4,109 MW (Scenario 1, 5 percent of annual energy from solar) to 28,766 MW (Scenario 7, 35 percent of annual energy from solar). Not surprisingly, especially on spring and fall days with light daytime demand, a large amount of solar output must be curtailed when solar penetration exceeds about 10 percent (8,219 MW). The primary reason for this is that inflexible nuclear power is serving much of the daytime demand and there is no place for the solar power to go. Without battery storage, the amount of solar power that can be utilized on light demand spring and fall days is limited, and excess solar generation must either be curtailed or exported.

Only one scenario (Scenario 9) includes battery storage. This is a deficiency in the NREL study. Scenarios 3-7, which include ever higher levels of solar capacity producing ever higher levels of solar power with no place to go without storage, are in effect a form of over-kill. The point is made with the first scenario, Scenario 3.

Scenario 9 misstates the ability of storage to fully absorb the excess solar generation by including far too little storage in the scenario. Scenario 9 matches 20,547 MW of solar capacity with 26,000 MWh of storage.[77] This equates to about one-and-a-quarter (1.25) hours of storage per MW of solar capacity.[78] This is similar to the ratio in the scenario that the Companies adopt in the Carbon Plan: 75 MW of solar capacity is combined with 80 MWh of battery storage. This equals 1.07 hours of storage per MW of solar capacity[79]

In spring and fall, solar will produce 4 to 5 MWh per day per MW of capacity.[80] In the case of Scenario 9, the 20,547 MW of solar capacity will produce 80,000 to 100,000 MWh of solar power per day, but there is only 26,000 MWh of storage capacity to absorb this solar output. This means that, solely due to underspecifying the amount of battery storage in Scenario 9, there will be a substantial amount of solar curtailment.

This is shown in Figure 6. The NREL study estimates that on a spring day, with 20,547 MW of installed solar capacity and no additional storage, about 63 percent of that spring day solar

[77] NREL, p. vii. Scenario 9: 25% solar = 20,547 MW solar (Scenario 5), and 1,000 MW of 4-hour storage, 1,000 MW of 6-hour storage, and 2,000 MW of 8-hour storage = 26,000 MWh of storage.
[78] 26,000 MWh ÷ 20,547 MW = 1.27 MWh storage per MW solar capacity.
[79] 80 MWh ÷ 75 MW = 1.07 MWh storage per MW solar capacity.
[80] NREL PV Watts Calculator, for Raleigh, NC, accessed February 14, 2021: https://pvwatts.nrel.gov/pvwatts.php.

production – about 65,000 MWh[81] – would have to be curtailed, as shown in Figure 6a. If 26,000 MWh of storage is added, consistent with Scenario 9, 40 percent of this 65,000 MWh of solar power would be directed to storage, while the other 60 percent would be curtailed. This is shown in Figure 6b, where 40 percent of the otherwise curtailed solar power is directed to storage (green fill).

Figure 6a. Scenario 5 (20,547 MW solar, spring day, no storage, 63 percent of solar, ~65,000 MWh, is curtailed)

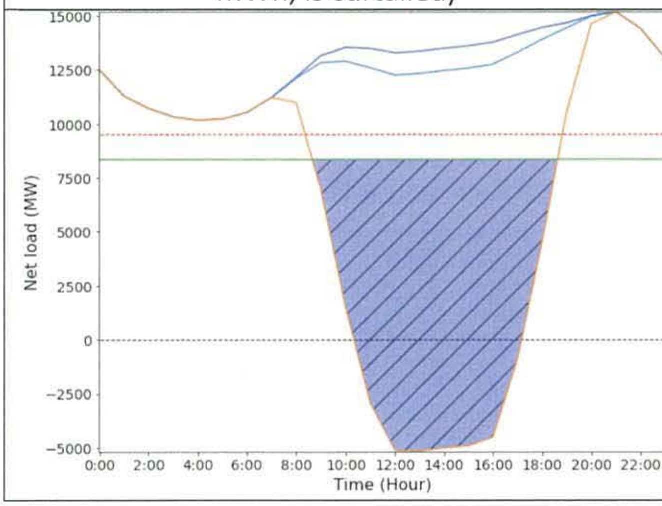
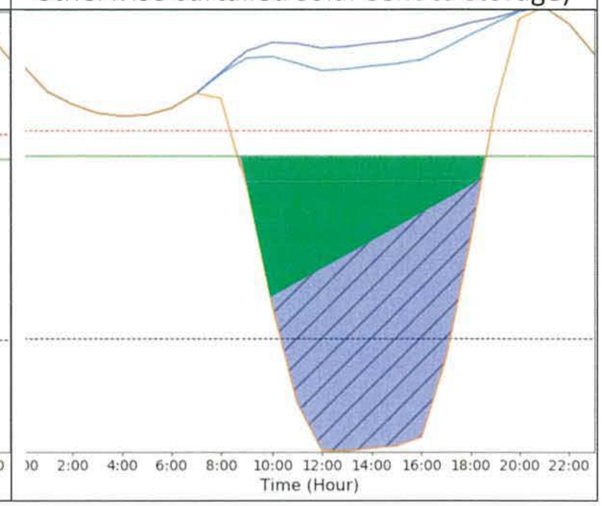


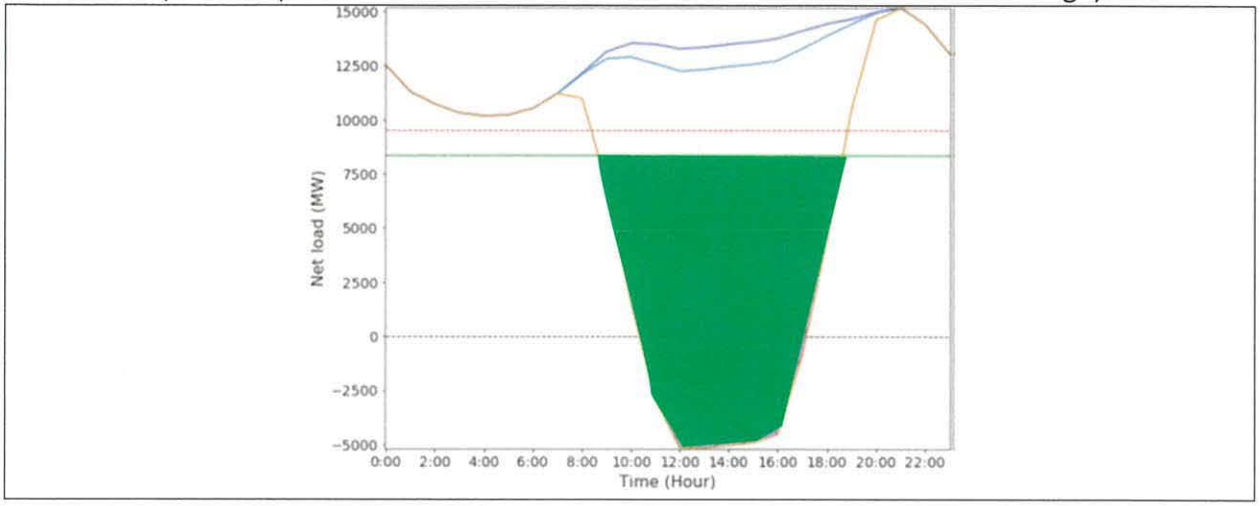
Figure 6b. Scenario 9 (20,547 MW solar, 26,000 MWh storage, ~40 percent of otherwise curtailed solar sent to storage)



What is missing from the 2020 NREL study, and from the Companies' Carbon Plan, is the scenario (or scenarios) that increases battery storage capacity sufficiently to eliminate, or nearly eliminate, solar power curtailments under light load spring and fall day conditions and to maintain the solar plus storage ELCC at or near 100 percent. For example, if Scenario 9 were modified to increase the amount of storage to 65,000 MWh, then the amount of solar curtailment in Scenario 9 would be reduced to zero as shown in Figure 7.

[81] Assume 5 MWh production per day per MW installed capacity. 5 MWh/MW x 20,547 MW = 102,735 MWh total solar production per day. 102,735 MWh per day x 0.63 curtailed = 64,723 MW per day curtailed.

Figure 7. Modified Scenario 9 with an increase of storage capacity to 65,000 MWh
(all solar power that would otherwise be curtailed is directed to storage)



This 2020 NREL study should not be relied upon by the Companies or the NCUC as a justification for rejecting SPS as the centerpiece of a carbon-neutral strategy for the Companies in North Carolina. The single solar and storage scenario analyzed by NREL (Scenario 9) leaves the mistaken impression that above some moderate threshold, with or without storage, much of the produced solar power will go to waste (curtailment). The Companies present this same erroneous information in the Carbon Plan as if it were a fundamental characteristic of the solar plus battery storage alternative.

This result is exclusively an artifact of the limitations placed on the solar plus storage scenario studied by NREL in 2020 and in the Carbon Plan in 2022, and not an inherent characteristic of a proper balancing of solar and storage resources. When the storage capacity is properly sized to the solar capacity, as shown in Figure 7, all of the solar capacity can be put to productive and reliable use, including on spring and fall days with light demand. There is no inherent operational ceiling on the amount of solar capacity that, when matched with properly-sized storage capacity, can provide reliable capacity to meet the Companies demand and provide fully dispatchable power.

Recommendation: The Companies should model three new solar plus storage profiles, solar plus 4-hour storage, solar plus 6-hour storage, and solar plus 8-hour storage, and provide the ELCCs for those profiles in a revised Carbon Plan.

V. New Nuclear Power Feasibility, Cost, and Safety Are Ongoing Unresolved Issues

Duke Energy includes Small Modular Reactors (SMRs) in all four Carbon Plan portfolios, despite the present lack of a commercially viable SMR. Bringing reliable and cost-effective SMRs into the marketplace remains highly speculative and high-risk, in spite of numerous SMR developers putting in years of effort. The challenges include unproven and challenging designs, cost viability and economies-of-scale, lack of full regulatory or investor approval, radioactive waste, safety and security, and competition from cheaper, safer alternatives. Any combination of these uncertainties remaining unresolved would make construction of SMRs unlikely.

The situation is reminiscent of the decade-plus effort by Duke Energy and other US utilities to design, license and construct the Westinghouse AP1000 reactor as part of the last "nuclear renaissance" beginning in 2005.[82] The effort ended in cancellation of all but one of the more than a dozen twin-reactor AP1000 projects that reached some stage of planning, licensing or construction. Billions of dollars in stranded costs were passed along to ratepayers, primarily across the Southeast. Duke Energy cancelled the last of its three failed projects in 2017.[83]

The manufacturer Westinghouse and utilities such as Duke Energy had claimed that the "Advanced Passive (AP) 1000" reactor would avoid the large cost overruns and mid-stream cancellations of the first generation of US nuclear power plant construction projects. That promise was largely based on plans for off-site construction of various modules that could then be pieced together at each proposed site. The AP1000 plan was not successful. In fact, the sole US AP1000 project still underway, Plant Vogtle Units 3 and 4 in Georgia, is years behind schedule with a cost of over $30 billion.[84] The same promise of off-site, modular construction used with the AP1000 is central to the promotion of SMRs.

NuScale, considered the leading US developer of SMR technology, is years behind schedule. Cost estimates for its SMR are speculative, as no units have yet been built or operated.[85]

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[82] The Guardian, *Reviving nuclear power debates is a distraction. We need to use less energy*, November 7, 2013,

[83] NCWARN News Release, *Duke Energy's Nuclear Boondoggle: Cancellation After Tragic Delay*, August 28, 2017: https://www.ncwarn.org/2017/08/duke-energys-nuclear-boondoggle-cancellation-after-tragic-delay-nc-warn-news-release/.

[84] GPB News, *Georgia nuclear plant's cost now forecast to top $30 billion*, May 9, 2022: https://www.gpb.org/news/2022/05/09/georgia-nuclear-plants-cost-now-forecast-top-30-billion.

[85] IFEEA, *NuScale's Small Modular Reactor - Risks of Rising Costs, Likely Delays, and Increasing Competition Cast Doubt on Long-Running Development Effort*, February 2022, pp. 6-9: https://ieefa.org/wp-content/uploads/2022/02/NuScales-Small-Modular-Reactor_February-2022.pdf.

NuScale reached agreement with Utah Associated Municipal Power Systems (UAMPS) in 2017 to build twelve 50 MW modules that would come online in 2024.[86] Later, the plan changed to six 77 MW modules projected to come online in 2029.[87] The currently projected NuScale production cost could be more than twice the cost of utility-scale solar and wind power generation.[88]

Investor reaction to NuScale's progress has been mixed. Despite going public in May 2022, NuScale still "needs substantial financing to stay afloat for the next several years" until its UAMPS project comes online.[89,90] Officials say current cash projections would carry the company until 2024. NuScale's problematic financial state would indicate a 2029 operational date for its SMR is highly problematic.

Radioactive waste is also a weakness of SMRs. A May 2022 research study found that, if ever built, SMRs will produce far more, not less, radioactive waste per MW generated than the typical US nuclear reactor.[91] SMRs would add to the intractable challenge the US has faced throughout the nuclear power era - How to safely manage spent fuel and other waste streams for generations to come.

VI. Conversion of CCs and CTs to 100% Hydrogen Is Problematic and Potentially Cost-Prohibitive

The Companies propose a tremendous build-out of CC and CT capacity on the presumption that all gas-fired generation will convert to 100 percent hydrogen (H_2) fuel by 2050, while at the same time acknowledging that the conversion to H_2 may not happen. The Companies make the following assertions, summarized in Table 5, about the proposed conversion to 100 percent H_2 in the Carbon Plan. The Companies, while acknowledging "significant uncertainties" in the future supply of H_2, simply assume that H2 will be available at scale in 2050 to operate all CCs

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86 Utility Dive, *NuScale makes public debut but requires 'a lot of financing' to launch small nuclear reactor in 2029*, June 1, 2022: https://www.utilitydive.com/news/nuscale-makes-public-debut-but-requires-a-lot-of-financing-to-launch-smal/624568/.
87 Utility Dive, *Newly public small modular reactor developer NuScale reports increased losses, big cash infusion*, June 8, 2022: https://www.utilitydive.com/news/newly-public-small-modular-reactor-developer-nuscale-reports-increased-loss/625102/.
88 IEEFA, February 2022.
89 Utility Dive, June 1, 2022, *supra* n.86.
90 Utility Dive, June 8, 2022, *supra* n.87.
91 Stanford News, Stanford-led research finds small modular reactors will exacerbate challenges of highly radioactive nuclear waste, May 30, 2022: https://news.stanford.edu/2022/05/30/small-modular-reactors-produce-high-levels-nuclear-waste/.

and CTs on 100 percent H_2. On that basis, the Companies propose to add 800 MW to 2,400 MW of CCs and 6,400 MW to 10,900 MW of CTs to achieve carbon neutrality by 2050.[92]

Table 5. Carbon Plan assertions regarding CT and CC conversion to 100% H_2 by 2050

Reference	Statement
Chp. 2, p. 18	Figure 2-4: Key Base Assumptions for Selectable Supply-Side Resources: • Hydrogen (H_2) blending at existing CC and CT units in 2035+ • Hydrogen market assumed available by 2040 • All new CTs 2040+ are assumed to be operated on 100% H2 • Existing CT and CC units on the system in 2050 as well as all CTs and CCs added to the portfolios operate on hydrogen in 205
App. E, p. 31	As 2050 approaches, the Companies assume hydrogen becomes a readily accessible fuel as a green hydrogen market develops.
App. E, p. 31	To account for the incremental equipment, the (post-2040) CT cost is increased to reflect these configuration changes to allow for operating 100% on hydrogen.
App. E, p. 32	All CCs that are selected in the Carbon Plan, regardless of the fuel supply assumption, are assumed to be converted to 100% operations on Hydrogen by 2050 to comply with the 2050 carbon neutrality target.
App. E, p. 43	First, starting in 2035, a small amount of hydrogen (1% by heat content, ~3% by volume) is assumed to be blended into the natural gas supply for all resources.
App. E, p. 43	Over time the amount of hydrogen blended into the natural gas fuel supply grows moderately (to 3% by heat content or approximately 10% by volume by 2038 and to 5% by heat content or approximately 15% by volume by 2041) but remains a small fraction of total fuel supply in the pipelines.
App. E, p. 43	By 2050, the remaining combustion units on the system are assumed to operate exclusively on hydrogen to meet the Carbon Plan modeling target of zero carbon emissions by 2050. The Carbon Plan assumes a green hydrogen market develops, by which hydrogen is produced from non-carbon emitting means, such as from excess energy from renewables or nuclear.
App. E, p. 43	Supply of hydrogen carries a significant uncertainty.

The Carbon Plan asserts that all CTs and CCs will burn 100 percent H_2 by 2050, if uncertainties around H_2 supply are resolved by then. There is no assessment of what happens with the CTs and CCs if those uncertainties are not resolved by 2050. The issue of stranded costs associated

[92] Carbon Plan, Chapter 1, p. 31.

with new gas-fired generation, and who will be responsible for those stranded costs, is not addressed by the Companies in the Carbon Plan.

This is an important question because the Companies propose to add a tremendous amount of gas-fired generation to achieve full carbon neutrality by 2050. Using Portfolio 1 as an example, the Companies propose to add 9,200 MW of gas-fired generation by 2050 in the base case. In the "limited natural gas" sensitivity case, 8,700 MW of gas-fired generation is added in the Portfolio 1 and 11,700 MW is added in Portfolio 4. See Tables 6 and 7.

Table 6. 2050 Carbon Plan resource mix base case, no natural gas supply constraints[93]

Table E-71: Final Resource Additions by Portfolio [MW] for 2050

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	New Nuclear[3]	PSH
P1	-9,300	19,900	1,800	7,400	2,400	6,800	800	9,900	1,700
P2	-9,300	18,200	1,700	5,900	2,400	6,400	3,200	9,900	1,700
P3	-9,300	19,000	1,800	6,400	2,400	7,500	0	10,200	1,700
P4	-9,300	18,100	1,800	6,100	2,400	6,800	800	10,200	1,700

Table 7. 2050 Carbon Plan resource mix with natural gas supply constraints[94]

Table E-84: Final Resource Additions by Portfolio [MW] for 2050

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	New Nuclear[3]	PSH
$P1_A$	-9,300	19,500	1,800	7,600	800	7,900	800	9,900	1,700
$P2_A$	-9,300	17,700	1,800	5,300	800	7,500	4,800	9,900	1,700
$P3_A$	-9,300	18,700	1,800	6,500	800	10,900	0	10,200	1,700
$P4_A$	-9,300	18,200	1,800	5,900	800	10,900	800	10,200	1,700

There is substantial risk that these gas-fired assets will be unable to operate on natural gas in 2050. There may be no clean fuel alternative if 100 percent H_2 is unavailable at that time.

There also is no accounting in the Carbon Plan for the potentially high capital cost of converting a CC or CT power plant designed to burn natural gas to burn 100 percent H_2. The Companies simply assume that green H_2 will be "readily accessible" in 2050.[95] All elements of the Companies existing CC and CT power plants that will operate beyond 2050 will likely require

[93] App. E, p. 77.
[94] Ibid, p. 86.
[95] Ibid, p. 31.

major modification to enable use of 100 percent H_2 fuel.[96,97] These elements include: fuel piping component materials, pipe sizes, sensors and safety systems, and gas turbine components exposed to H_2 combustion exhaust gases.[98] There is no indication that the Companies have considered the additional cost of converting the CC and CT power plants to burn 100 percent H_2, or the potentially high fuel cost of green H_2 that will be required.

VII. Reserve Margins Too High in Carbon Plan, Translate Into 1,000s of MW of Unnecessary New Capacity

The Carbon Plan is closely tied to the 2020 DEC and DEP IRPs, as the Companies explained in the Carbon Plan. The statements made by the Companies about the strong nexus between the 2020 IRPs and the Carbon Plan are provided in Table 8. It is because of this strong nexus that this section addresses assertions regarding portfolios, reserve margins, demand growth, and demand side management (principally energy efficiency and net-energy metered solar) in both the 2020 IRPs and the Carbon Plan.

Table 8. Similarity of 2022 Carbon Plan Portfolios and 2020 IRP Carbon Reduction Portfolios

Source	Statement
Chp. 1, p. 1	Like the Companies' Integrated Resource Plans ("IRP") and associated IRP updates submitted to the North Carolina Utilities Commission ("Commission") and the Public Service Commission of South Carolina ("PSCSC") in 2020, the Plan presents multiple potential portfolios for the Companies to meet future energy and demand requirements and assesses the associated risks, benefits, and costs to customers of the portfolios.
Chp. 1, p. 1	Like the IRPs, the Plan identifies multiple supply- and demand-side resource combinations needed to meet the Companies' projected demand over time to ensure reliable service to customers.
Chp. 1, p. 1	Also like the 2020 IRPs, the Plan targets further reductions in carbon emissions. While directionally similar to Portfolio C in the 2020 IRPs, which accomplished a 66% reduction in CO2 by 2030, the Plan represents a more updated resource analysis that would achieve 70% CO2 emissions reductions by 2030, 2032 or 2034 with wind and nuclear.
Chp. 2, p. 6	Consistent with the Companies' 2020 Integrated Resource Plans ("IRPs"), the Companies used a 17% minimum winter planning reserve margin in

[96] App. E, p. 23. "A limited number of natural gas resources currently on the system are expected to continue operating in 2050 and beyond. These include the WS Lee CC, the Asheville CCs, Sutton CTs 4 and 5, and Lincoln CT 17. For these combustion units that are planned to remain on the system in 2050, the Carbon Plan assumes these units are converted to hydrogen-fired units near the end of the planning horizon. In the Carbon Plan modeling, these units operate exclusively on hydrogen to comply with the 2050 carbon neutrality target."
[97] Siemens, *Hydrogen power with Siemens gas turbines*, 2020, p. 16.
[98] Ibid.

	developing the Carbon Plan portfolios based on results from the 2020 Resource Adequacy Study conducted by Astrapé Consulting.
Chp. 2, p. 6	The 2020 Resource Adequacy Study reports for DEC and DEP are included as Attachments I and II to the Carbon Plan.

A. The Companies Add Far More Capacity Than Necessary for Reliability Purposes

The Companies rely on the consultant (Astrapé) reserve margin studies presented with the 2020 DEC and DEP IRPs in the Carbon Plan.[99] This is the basis for designing the Carbon Plan portfolios to achieve a 17 percent winter peak planning reserve margin (PRM). The PRM is the sum of all available resources compared to the peak load that must be met. In the case of Carbon Plan Portfolio 1, the only portfolio designed to achieve 70 percent carbon reduction by 2030, the PRM is 26.3 percent in 2030 and rises to 29.0 percent in 2035.[100] These PRM values represent reserves in excess of 17 percent of about 3,000 MW in 2030 and 4,300 MW in 2035.[101]

Both DEC and DEP included, for the first time in their 2020 IRPs, the actual operating reserve margin (ORM) on extreme winter peak days in the 2014-2019 period where the ORM declined below 10 percent.[102] The ORM is the sum of all available resources minus resources in planned or forced outage compared to the forecast peak load. These 2020 IRP ORM analyses were conducted by the Companies to assert that the ORM should be the controlling reliability parameter, and not the 17 percent PRM requirement.

There were no winter days after 2015 where the ORM dropped below 5 percent in DEC or DEP territories, and no winter days in 2016 or 2017 where the ORM declined below 10 percent in either DEC or DEP territories. According to the ORM data presented for 2014-2019, there are thirteen days below 10 percent ORM in DEC territory,[103] and ten days below 10 percent ORM in DEP territory.[104] The North American Electric Reliability Corporation ("NERC") requires that utilities such as DEC and DEP maintain an ORM of at least 6 percent at all times to assure grid reliability.[105]

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[99] App. E, p. 10.

[100] App. E, pp. 64-65, Table E-58: Reliability Metrics for As-Found Portfolios, 2030; Table E-59: Reliability Metrics for As-Found Portfolios, 2035.

[101] App. E, p. 20, Table E-19: Carbon Plan Base Load Forecast – Winter Peak [MW]. DEC + DEP winter peak in 2030 = 32,226 MW; DEC + DEP winter peak in 2035 = 35,981 MW. Excess MW above 17% PRM in 2030 = 32,226 MW (1.263 – 1.17) = 2,997 MW. Excess MW above 17% PRM in 2035 = 35,981 MW (1.29 – 1.17) = 4,318 MW.

[102] DEC's 2020 IRP, p. 69; DEP's 2020 IRP, p. 71.

[103] DEC's 2020 IRP, Table 9-A, p. 71.

[104] DEP's 2020 IRP, Table 9-A, p. 73.

[105] BAL-002-WECC-3—Contingency Reserve, August 15, 2019, p. 1: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf. "The amount of Contingency

The actual ORMs on these peak winter days are compared to the PRM for the respective year. The Duke Energy planning target for the PRM is 17 percent.[106] The difference between the PRM and the ORM is that the PRM includes all supply resources, while the ORM only includes those supply resources that are not in planned or forced outage.

For all DEC and DEP 2014-2019 winter peak days when the ORM was below 5 percent, the PRM was 24.8 percent or higher. Both DEC and DEP present this ORM data to make the case that they are not carrying excessive planning reserves, stating that – at least on the days with the tightest ORMs – they would have had to shed firm load if the PRM going into the winter had been only 17 percent.[107] However, DEC and DEP acknowledge they did not include non-firm energy purchases that did occur on those "ORM less than 10 percent" days when calculating the ORMs shown.[108]

These "low ORM" tables are apparently meant to demonstrate that accelerating the retirement of existing DEC and DEP resources is inadvisable despite the fact that DEC and DEP are maintaining PRMs far above the 17 percent PRM target. As noted, the Companies project a PRM of 26.3 percent for Portfolio 1 in 2030 and 29.0 percent in 2035.[109]

However, information provided by Duke Energy in response to NC WARN data requests in the 2020 IRP proceeding, and Duke Energy statements to the NCUC following the February 20, 2015 winter peak day (for both DEC and DEP), calls into question the accuracy of the calculated ORMs that the Companies are using to justify the need for PRMs well above 17 percent.

To begin, in response to a data request by Southern Environmental Law Center, Duke Energy lowered the winter peak demand values shown in the DEC IRP for a number of the low ORM days listed.[110] The original and revised winter peak values are shown in Table 9, along with the original ORM and recalculated ORM.

Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

[106] DEC's IRP, p. 69; DEP's IRP, p. 71; Carbon Plan, App. E, p. 10.

[107] Ibid.

[108] DEC's 2020 IRP, p. 71; 2020 DEP IRP, p. 73: "The operating reserves shown do not reflect non-firm energy purchases during the hour of the peak system demand in order to ensure a fair comparison with planning reserve margins which also do not include such non-firm purchases that may or may not be available during peak demand hours."

[109] App. E, p. 64, Table E-58: Reliability Metrics for As-Found Portfolios, 2030 (Portfolio 1); p. 65, Table E-59: Reliability Metrics for As-Found Portfolios, 2035 (Portfolio 1).

[110] DEC-DEP's Response to SELC's Data Request 2-12 in NCUC Docket No. E-100, Sub 165 (see supporting Excel spreadsheet), attached hereto as **Attachment 2**.

Table 9. Selected dates from DEC Table 9-A "winter peak days with lowest ORMs" – original and corrected

Date	Peak demand in Table 9-A (MW)	ORM in Table 9-A (%)	Revised highest winter day peak demand (MW)	Revised ORM (%)
1/30/14	19,151	2.4	18,275	7.3[111]
01/05/18	21,620	8.0	19,077	22.4[112]
1/31/19	18,875	7.2	16,880	19.9[113]

The corrected winter peak demand values result in dramatically increased ORMs for a number of DEC winter peak dates. The all-time high winter peak demand for DEC occurred on January 5, 2018. DEC used the ORM of 8.0 percent on this date, which it calculated using an incorrect peak load of 21,620 MW, as part of its advocacy for PRMs in the 25 percent range or higher.[114] Use of the correct winter peak demand for January 5, 20018 increases the ORM above 20 percent. The subsequent changes provided in Duke Energy data request responses to winter peak demand values in Tables 9-A in the DEC and DEP 2020 IRPs nullify the usefulness of the ORM data in the tables.

What also renders Table 9-A inaccurate in both the DEC and DEP IRPs is the failure to include the quantity of non-firm imports relied upon to meet the winter peak. Duke Energy acknowledges that it did not include non-firm imports when calculating the ORMs in Table 9-A, because non-firm purchases may not be available during peak demand hours.[115] However, Duke Energy then states it assumes that it "will rely on" 29 percent of its reserve margin being met with non-firm supply.[116] The Companies make the same statement qualitatively in the Carbon Plan, indicating the base case includes reliance on imports.[117] Not only is Table 9-A in the DEC

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[111] 19,151 MW x 1.024 = 19,611 MW. 19,611 MW ÷ 18,275 MW = 1.073 (7.3 percent reserve margin)
[112] 21,620 MW x 1.08 = 23,350 MW. 23,350 MW ÷ 19,077 MW = 1.224 (22.4 percent reserve margin)
[113] 18,875 MW x 1.072 = 20,234 MW. 20,234 MW ÷ 16,880 MW = 1.199 (19.9 percent reserve margin)
[114] DEC's 2020 IRP, p. 69. "Planning reserves ranged from approximately 21% to 28%. Yet, without non-firm market assistance the Company would have shed firm load."
[115] DEC's 2020 IRP, p. 71. "The operating reserves shown do not reflect non-firm energy purchases during the hour of the peak system demand in order to ensure a fair comparison with planning reserve margins which also do not include such non-firm purchases that may or may not be available during peak demand hours."
[116] Ibid, p. 72. "It is important to note that Base Case results reflect the regional benefits of relying on non-firm market capacity resulting from the weather diversity and generator outage diversity across the interconnected system. However, there is risk in over reliance on non-firm market capacity. The Base Case reflects a 6.5% decrease in reserve margin compared to the Island Case (from 22.5% to 16.0%). Thus, approximately 29% (6.5/22.5 = 29%) of the Company's reserve margin requirement is being satisfied by relying on the non-firm capacity market."
[117] App. E., p. 10. "Astrapé examined resource adequacy for a number of scenarios: an island scenario which assumes no market assistance is available from neighbor utilities; **a base case**, which reflects the reliability

and DEP IRPs inaccurate due to revised winter peak values, the table(s) are also inaccurate because DEC and DEP are in fact relying on substantial amounts of non-firm supply to meet their reserve margin requirements.

Duke Energy preferentially relies on non-firm purchases to meet winter peak demand while leaving substantial amounts of its own supply assets idle. The company provided, in response to NC WARN data requests,[118] lists of all DEC and DEP generators that were in reserve and not operational on the low ORM winter peak days listed by DEC and DEP in their 2020 IRPs. For all dates, DEC and DEP had 1,000s of MW of CTs, pumped storage, hydro, CCs, and coal units in reserve and available to meet demand. The capacity (MW) of units held in reserve on January 5, 2018, the all-time winter peak high for DEC and a day when DEP also experienced a near record winter peak, and the ORM capacity these reserves represent, are provided in Table 10.

Table 10. Quantity (MW) of available unused DEC and DEP supply on day with record high DEC and DEP winter peak, January 5, 2018, and equivalent ORM

Date	Peak demand (MW)	Unused and available supply assets[119] (MW)	Equivalent ORM[120] (%)
DEC			
01/05/18	19,077	CT = 1,071 MW pumped storage = 547 MW hydro = 241 MW coal = 49 MW steam = 168 MW DSM = 428 MW Total = 2,504 MW	13.1 (no non-firm imports) 18.5 (non-firm imports add 29% to reserve margin)
DEP			
01/05/18	15,048	CT = 857 MW CC = 103 coal = 24 DSM = 478 MW Total = 1,462 MW	9.7 (no non-firm imports) 13.7 (non-firm imports add 29% to reserve margin)

benefits of the interconnected system including the diversity in load and generator outages across the region; a combined case, which allowed preferential support between DEC and DEP to approximate the reliability benefits of operating the DEC and DEP generation systems as a single balancing authority . . ."

[118] DEC-DEP's Responses to NCWARN's Data Request 4-5 in Docket No. E-100, Sub 165, attached hereto as **Attachment 3**.

[119] Only units identified by Duke Energy as in forced outage are excluded from the totals. Units in planned maintenance outage are included, as improper timing of maintenance outages is not valid reason to exclude otherwise available supply.

[120] DEC example: (19,077 MW + 2,504 MW)/19,077 MW = 1.131 (13.1%). 13.1% ÷ (1 – 0.29) = 18.45%.

DEC indicated that its forecast cumulative available capacity in the winter of 2017/2018 was 22,722 MW.[121] The projected winter peak load was 18,712 MW, and the planning reserve margin at the winter peak was forecast at 21 percent. The Duke Energy data response providing outage data for the winter peak days in Table 9-A indicates that one generator, combustion turbine Lincoln CT 16, 97 MW, was in forced outage on January 5, 2018.[122] Therefore, DEC had 22,625 MW of its own resources available on January 5, 2018 to meet an actual peak load of 19,077 MW. That is an ORM of 18.6 percent,[123] without considering the non-firm imports DEC and DEP routinely rely on at the winter peak to supplement their own capacity.

The amount of available supply that DEC had at its disposal but did not utilize on the four 2019 low ORM winter peak days identified by DEC ranged from about 20 percent to 40 percent of the actual winter peak.[124] No low ORM winter peak days were reported by DEP in 2019.[125]

Non-firm imports that DEC and DEP rely on to meet the winter peak are reliably available for that purpose. These non-firm imports in the DEC and DEP systems ". . . reflect the regional benefits of relying on non-firm market capacity resulting from the weather diversity and generator outage diversity across the interconnected system."[126]

This weather diversity is represented by the balancing authorities to the north (PJM) and south (Georgia Power/Southern Company) of DEP and DEC. PJM and Southern Company are "summer peaking" territories.[127,128] The PJM summer peak is approximately 20,000 MW higher than the winter peak.[129] As a result PJM and Southern Company have ample reserves available for export to meet DEC and DEP winter peak demand, even when DEC and DEP are experiencing simultaneous winter peaks, as they did on January 5, 2018.[130]

As a point of comparison, the DEC and DEP IRPs point out that PJM limits non-firm purchases to 3,500 MW.[131] 3,500 MW represents a 20 percent reserve margin on DEC's all-time January 5,

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[121] NCUC Docket No. E-100, Sub 147, DEC's 2016 IRP, September 1, 2016, p. 40.

[122] DEC-DEP's Responses to NCWARN's Data Request 4-5 in Docket No. E-100, Sub 165, attached hereto as **Attachment 3**.

[123] 22,675 MW ÷ 19,077 MW = 1.186 (18.6 percent reserve margin)

[124] DEC-DEP's Responses to NCWARN's Data Request 4-5 in Docket No. E-100, Sub 165, attached hereto as **Attachment 3**.

[125] DEP's 2020 IRP, Table 9-A, p. 73.

[126] DEC's 2020 IRP, p. 72.

[127] PJM, *PJM Load Forecast Report*, January 2020, p. 5. See: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx.

[128] Georgia Power Company, *Budget 2019 Load and Energy Forecast 2019 to 2038*, Section 6, p. 82. "Georgia Power is a summer peaking utility over the entire forecast horizon."

[129] PJM, *PJM Load Forecast Report*, January 2020, p. 5.

[130] DEC's 2020 IRP, p. 71 (01/05/18, 21,620 MW); DEP's 2020 IRP, p. 73 (01/05/18, 15,048 MW).

[131] DEC's 2020 IRP, p. 72.

2018 winter peak load.[132] However, Duke Energy is not a member of PJM. It is not limited to 3,500 MW of non-firm imports.

Duke Energy relies on this imported power on the most critical winter peak days, as it did on February 20, 2015.[133] Duke Energy asserted in the 2020 IRPs that on February 20, 2015 DEP operated a negative ORM of -1.6 percent, while DEC was operating at an ORM of only 1.2 percent.[134] However, in response to NCUC inquiries about lack of capacity on February 20, 2015, Duke Energy assured the NCUC shortly after the event that it had access to ample supply via multiple transmission import pathways and had no reliability problems that day.[135] An important source of supply to meet the February 20, 2015 winter peak was non-firm imports from neighboring balancing authorities.

It is standard DEC and DEP practice to import substantial amounts of reliable non-firm energy from neighboring balancing authorities to meet their respective winter peak loads.[136] This means that both DEC and DEP maintain larger generation fleets than are necessary to reliably meet reserve margin targets, as DEC and DEP calculate the reserve margins assuming only assets owned or controlled by them will be available to meet demand. Reliable non-firm imports can be relied upon by Duke Energy to meet peak winter demand.

It is routine practice in other balancing areas to assume some level of non-firm imports will be available to provide reliable supply at the time of peak demand.[137] For example, New England ISO met about 17 percent of its January 2020 winter peak demand with a mix of firm and non-firm imports.[138,139] The NCUC should insist that Duke Energy include a reasonable contribution by non-firm imports to the DEC and DEP winter peak reserve margins. The recognition of this

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[132] 3,500 MW ÷ 19,070 MW = 0.183 (18.3 percent).

[133] Transcript of NCUC Staff Conference, March 2, 2015, attached hereto as **Attachment 4**.

[134] DEC and DEP's 2020 IRPs, Table 9-A.

[135] Transcript of NCUC Staff Conference, March 2, 2015, pp. 11-12, attached hereto as **Attachment 4**. Duke Energy VP Mr. Peeler was asked by the NCUC Chairman, "So how far were you away from having to shed load?" Mr. Peeler stated, "Well, so certainly there were several other options still available. We had not called on VACAR reserves, so we still had firm transmission availability to bring reserves in. There were still energy options. We still could have pushed more non-firm energy."

[136] NCUC, March 2, 2015 transcript, p. 17 *supra* n.133.

[137] DEC's 2020 IRP, p. 72. "Base Case results reflect the regional benefits of relying on non-firm market capacity . . . Thus, approximately 29% (6.5/22.5 = 29%) of the Company's reserve margin requirement is being satisfied by relying on the non-firm capacity market."

[138] NE-ISO, 2020 Net Energy and Peak Load by Source (xls spreadsheet), February 18, 2021: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load. Imports at the January 2020 peak were 3,065 MW at a system peak load of 18,097 MW.

[139] NE-ISO, Resource Mix, webpage accessed February 22, 2021: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load. "About 1,500 MW in summer and 1,000 MW winter of imported electricity are obligated to be available for the region—mostly hydropower from Eastern Canada."

reality would enable Duke Energy to retire significant amounts of existing generation without reducing its ability to maintain adequate ORMs on extreme winter peak demand days.

Duke Energy is operating its coal plants as peakers or seasonal intermediate supply.[140] Acknowledging reliance on non-firm imports to meet winter and summer peaks, up to and beyond 3,500 MW, would facilitate coal plant retirements.

For the one winter day in the 2014-2019 record with the highest "same day" demand on the DEC and DEP systems and the lowest ORMs (as shown in Table 9-A of the IRPs), February 20, 2015, Duke Energy has provided the quantity of hourly non-firm imports relied on to meet the 7 am – 8 am winter peak that day.[141] These non-firm imports were substantial and are shown in Table 11.

Table 11. Non-firm imports relied on by DEC and DEP on February 20, 2015

Utility receiving non-firm imports	Source of non-firm imports	Quantity of non-firm imports (MW)
DEC	Santee Cooper	1,412
	Alcoa Power - Yadkin Division	256
DEP-East	PJM Interconnection	1,391
DEP-East	South Carolina Gas & Electric	932
DEP-West	TVA	248
DEP-West	PJM Interconnection	698

Duke Energy had additional supply options on February 20, 2015 beyond the non-firm supply listed in Table 3. The company provided NCUC with a narrative explanation of the power supply tools it had at its disposal on that day to assure grid reliability:[142]

> We were able to bring in – you know, I think we were importing about 1,200 MW of energy at one time into our BAA. That's a sizable energy move in a very stressful time. So we were able to move energy in from PJM. We moved energy in from Southern Company. We had our reserve sharing capabilities on our firm transmission. So I didn't see any deficiencies."

[140] *E.g.*, DEC's 2020 IRP, Table 11-A: Ranking of Coal Plants for Retirement Analysis, p. 79.
[141] DEC-DEP's Responses to NCWARN's Data Request 5-3(c) in Docket No. E-100, Sub 165 (see Excel spreadsheet produced with the data response). The pertinent spreadsheet is not readily convertible to PDF format for filing. However, NCWARN can submit the spreadsheet in native Excel format upon request.
[142] **Attachment 4**, Transcript of NCUC Staff Conference, March 2, 2015, p. 17.

One of these supply alternatives is the Virginia – Carolina Region of the Southern Electric Reliability Council (VACAR), created to share reserves with participating balancing authorities including DEC and DEP:[143]

> VACAR Reserve Sharing: PJM, on behalf of Dominion-Virginia Power, participates in the VACAR reserve sharing group, which consists of Dominion-Virginia Power, Duke Power (DEC), South Carolina Electric and Gas, Progress Energy-Carolinas (DEP) and South Carolina Public Service Authority (Santee Cooper). The purpose of the agreement is to share reserves to enhance reliability and to decrease the cost of maintaining reserves for each system. Upon the telephone request of a member, the responding member will provide reserve energy for a period of up to 12 hours to support the needs of the requesting member.

Despite the record winter peak load on February 20, 2015, Duke Energy had ample reserves without calling upon the substantial VACAR reserves that it also had at its disposal.[144]

Recommendation: The Companies are maintaining excessive reserve margins. Adjusting the current supply portfolio to meet the PRM target of 17 percent would enable the immediate retirement of at least 3,000 MW of capacity while meeting the target PRM of 17 percent. This would enable retirement of the Mayo and Roxboro coal plants, with a combined capacity of about 3,200 MW, in 2024 while meeting a 17 percent PRM.

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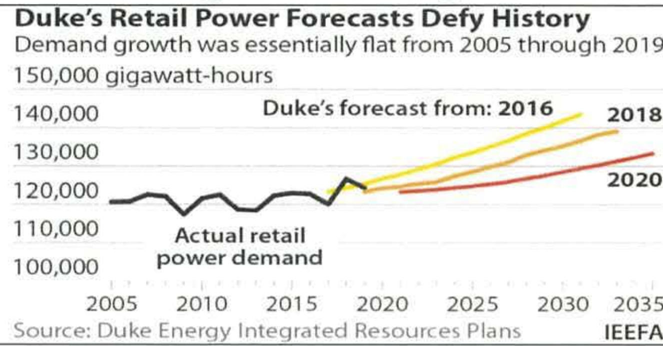
[143] PJM, *PJM Manual 12: Balancing Operations, Revision: 42*, January 27, 2021, p. 37.
[144] **Attachment 4**, NCUC, March 2, 2015 transcript, pp. 11-12.

VIII. The Companies Forecast Demand Growth Rates Are Substantially Higher Than Actual Recent Trend

DEC and DEP have consistently overestimated demand growth in their respective service territories, as shown in Figure 8.

Figure 8. Comparison of Duke Energy actual demand growth to forecast demand growth[145]



A. DEC Forecast Demand Growth Rate in Carbon Plan Is Too High – DEC Demand Is Not Increasing

Actual DEC retail sales growth from 2016 through 2021, the most recent five-year period shown in the Carbon Plan, averaged 0.0 percent.[146] The Companies analyze the period 2012 to 2021 to assert a sales growth rate forecast for DEC of 0.8 percent.[147] 2012 was a relatively low retail sales year, as can be seen in Figure 8. Using 2012 as the base year gives the impression of significant demand growth over time, when review of the record going back to 2007 shows no growth. The Duke Energy retail sales growth rate forecast used in the Carbon Plan is not supported by actual historical DEC retail demand.

DEC is projecting in its base-case resource forecast that its annual retail sales will increase by 0.7 percent per year and will rise by an estimated 6,974 GWh by 2035.[148] This is equivalent to the output of two new 500 MW CC plants. Two 500 MW CC plants running at capacity factors of 75 percent would generate about this amount of electricity on an annual basis.[149] The justification for this new capacity would be eliminated with an accurate DEC demand forecast.

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[145] D. Wamsted - Institute for Energy Economics and Financial Analysis, *Key Shortcomings in Duke's North Carolina IRPs: An Issue-by-Issue Analysis: Part 2*, February 2021: http://ieefa.org/wp-content/uploads/2021/02/Key-Shortcomings-in-Duke-North-Carolina-IRPs_Part-2_February-2021.pdf.

[146] App. F, p. 16. Table F-14: Electricity Sales (GWh) – DEC.

[147] App. F, p. 15. "Historical Retail Sales growth over the presented period was 0.9% and 0.8% respectively for DEC and DEP."; p. 19. "Projected Retail sales growth is 0.8% and 0.4% for DEC and DEP."

[148] App. F, p. 20, Table F-16: Forecasted Energy Sales by Class – DEC.

[149] 1,000 MX x 8,760 hr/yr x 0.75 = 6,570,000 MWh/yr.

B. DEP Forecast Demand Growth Rate in Carbon Plan Is Too High – DEP Demand Is Declining

The Carbon Plan retail sales data shows that actual DEP retail sales declined from 2016 through 2021, the most recent five-year period, at a rate of -0.7 percent.[150] The Companies analyze the period 2012 to 2021 to assert a sales growth rate forecast for DEP of 0.4 percent.[151] 2012 was a relatively low retail sales year. Using 2012 as the base year gives the inaccurate impression of demand growth over time. DEP demand is declining.

DEP is projecting in its base-case demand growth forecast that its annual retail sales will increase by 0.4 percent per year, rising by an estimated 1,455 GWh by 2035.[152]

The combined 2035 forecast increase in annual retail sales between DEC and DEP above 2023 demand is 8,429 GWh. is equivalent to the output of about 1,300 MW of CC capacity running at a capacity factor of about 75 percent.[153] This new capacity would not be justifiable with an accurate DEP demand forecast.

The Companies attribute significant load growth, both annual energy and peak load, to the increase over time of electric vehicles (EVs).[154] Such load growth is not inevitable. Accelerated growth of NEM solar would offset increased energy demand due to EV charging. The Companies recognize this scenario in the Carbon Plan, identifying it as the "high NEM sensitivity" case.[155] Minimizing or eliminating the EV charging contribution to peak load could also be achieved by structuring the EV tariff to include very high rates during on-peak hours (for example).

The last fifteen years of data on the Companies' annual retail sales (Figure 8) and winter peak demand trends[156] provide no basis for projecting any annual energy demand or peak load growth going forward. Much of the CT and nuclear build-out proposed by the Companies in the 2035 to 2050 timeframe is designed to meet load growth that is highly unlikely to materialize.

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[150] App. F, p. 17. Table F-15: Electricity Sales (GWh) – DEP.
[151] App. F, p. 15. "Historical Retail Sales growth over the presented period was 0.9% and 0.8% respectively for DEC and DEP."; p. 19. "Projected Retail sales growth is 0.8% and 0.4% for DEC and DEP."
[152] App. F, p. 21. Table F-17: Forecasted Energy Sales by Class – DEP.
[153] 1,300 MW x 8,760 hr/yr x 0.75 = 8,541,000 MWh/yr (8,541 GWh/yr)
[154] App. F, pp. 12-15.
[155] App. E, p. 17. "Base Net Energy Metering ("NEM") growth reflects currently approved net metering rate designs in the Carolinas as of January 1, 2022. The high NEM sensitivity, which is used in the low load forecast, envisions future program offerings that would drive additional NEM growth in the Carolinas . . ."
[156] App. F, pp. 18-19 (System Peaks).

IX. The Generation Mix to Meet the Summer Peak and the Winter Peak Should Be Addressed in the Carbon Plan

A. Summer Peak Should Also Be Evaluated

The Companies' all-time summer and winter peak loads are comparable in magnitude.[157] Summer peak loads in DEC and DEP territories in 2021 were significantly higher than the 2020/2021 winter peak loads.[158] Yet the Companies use only the winter peak condition as the design basis for the Carbon Plan portfolios. The Companies' justification for this approach, that "the annual peak demand net of non-dispatchable solar and wind is projected to occur in winter," is only true because the Companies are not adding sufficient battery storage to the portfolios to make those renewable resources dispatchable in winter.

This is the wrong approach. Sufficient battery storage should be added to the solar resource in the portfolios to assure the solar capacity is fully dispatchable in summer and winter.[159] The neighboring utilities to the Companies are summer peaking utilities with ample power surpluses to share with the Companies during winter peak conditions.[160] It is more critical for planning purposes that the Carbon Plan portfolios can reliably address the summer peak, the season when the Companies cannot rely on importing large amounts of power from neighboring utility service territories.

B. Failure to Deploy Available DSM at the Winter Peak Is Creating Avoidable Winter Peaks

The highest winter peak demand in the DEC and DEP systems in recent years occurred in the first two weeks of January 2018. DEC deployed no DSM on its winter peak day and DEP deployed about half of the DSM available to it on its winter peak day.

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[157] Duke Energy press release, *Duke Energy Carolinas customers set summertime record for electricity use*, June 15, 2022: https://news.duke-energy.com/releases/duke-energy-carolinas-customers-set-summertime-record-for-electricity-use-6873667. DEC (NC + SC) all-time summer peak = 21,086 MW. DEC (NC + SC) all-time winter peak = 21,620 MW.
[158] DEC, 2021 FERC Form 1, April 18, 2022, p. 401b. February 2021 DEC 2020/2021 winter peak = 15,449 MW, July 2021 DEC 2021 summer peak = 17,337 MW; DEP, 2021 FERC Form 1, April 18, 2022, p. 401b. January 2021 DEP 2020/2021 winter peak = 11,873 MW, August 2021 DEP 2021 summer peak = 12,655 MW.
[159] The battery storage component of the SPS would be recharged with off-peak grid power when the associated solar power is unavailable, and would operate as if it were a standalone battery under those conditions.
[160] NCWARN-CBD's Initial Comments in NCUC Docket No. E-100, Sub 165, March 1, 2021, Attachment 1, Powers' Report, p. 1.

DEC had 428 MW of DSM available to meet the winter peak in 2018.[161] However, DEC did not deploy any DSM for that purpose as summarized by NCUC: [162] "The Public Staff noted that DEC's 2018 annual system (winter) peak demand of 19,436 MW occurred on January 5, 2018. . . DEC did not activate any of its DSM resources during either the winter system peak or the summer peak." The amount of DSM that DEC did not deploy, 428 MW, is roughly equivalent to the output of DEP's 560 MW Asheville CC power plant.

DEP had 478 MW of DSM available to meet the winter peak in 2018.[163] No DSM was deployed by DEP on January 5, 2018,[164] a day with high winter peak demand and relatively low ORM. It deployed less than half of that quantity, 225 MW, on its winter peak day of January 7, 2018.[165] DEP's peak demand reached 16,191 MW on that day.

Both DEC and DEP are using examples of low ORMs on winter peak days to justify PRMs that are much higher than Duke Energy's 17 percent PRM target. However, neither company is consistently using the available DSM resources to increase the ORM on winter peak days and reduce the justification for excessive PRMs.

X. Despite Companies Identifying "Grid Edge" Technologies as the First Priority in the Carbon Plan, NEM Solar Has Minor Role

The Carbon Plan states it uses a three-pronged approach, focusing first on "grid edge" strategies, including NEM solar, to reduce energy requirements and load profiles. The Carbon Plan underscores that:[166]

> The Companies first plan to "shrink the challenge" by reducing energy requirements and modifying load patterns through grid edge and customer programs allowing more tools to respond to fluctuating energy supply and demand.

Grid edge programs are identified as the first priority in the Carbon Plan. Grid edge programs include energy efficiency (EE), demand-side management (DSM), customer self-generation (NEM solar), voltage management and other distributed energy resources (DER).[167] The Carbon

[161] DEC's 2019 IRP, September 5, 2018, p. 162.
[162] NCUC, *Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service In North Carolina*, December 31, 2019, Appendix 1, p. 33.
[163] DEP's 2018 IRP, p. 156.
[164] Ibid, pp. 253-254.
[165] NCUC, *Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service In North Carolina*, December 31, 2019, Appendix 1, p. 32.
[166] Carbon Plan, Executive Summary, p. 9.
[167] App. G, p. 1.

Plan forecasts 15 percent growth rate for NEM solar through 2030.[168] However, the Companies have proposed modifications to the NEM tariff that will reduce the economic benefit of NEM by 30 percent or more to address an alleged cost shift from NEM residential customers to non-NEM residential customers.[169]

The Companies' growth projection for NEM has substantially declined between the 2020 DEC and DEP IRPs and the Carbon Plan. There were 169 MW of NEM solar online in the Companies' territories in North Carolina at the end of 2021.[170] The Companies projected in the 2020 IRPs that 745 MW would be online in North Carolina by 2035.[171] This is a NEM solar increase in North Carolina of 576 MW between the end of 2021 and 2035.

The Carbon Plan projects a NEM addition rate of 26.5 MW per year in North Carolina,[172] the equivalent of an additional 371 MW by 2035.[173] The Carbon Plan reduces the role of NEM solar dramatically, relative to the 2020 IRP forecasts, despite identifying NEM solar as a first priority in reducing carbon emissions. The NEM solar additions forecast in the 2020 IRPs were made in the context of the Companies modifying the NEM tariff to reduce bill savings.[174] That process is underway in NCUC Docket E-100 Sub 180. No new rationale is put forth in the Carbon Plan to justify the substantial decline in new NEM solar capacity in North Carolina between the Companies' 2020 IRP(s) forecast and the Carbon Plan forecast.

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[168] Carbon Plan, Chp. 2, p. 12.

[169] Joint Initial Comments of NC WARN, NCCSC, and Sunrise Durham in the Matter of Investigation of Proposed Net Metering Policy Changes, NCUC Docket No. E-100 Sub 180, March 29, 2022.

[170] Total Companies NEM solar capacity at end of 2021, per EIA 2021 NEM database (https://www.eia.gov/electricity/data/eia861m/#netmeter): DEC NC = 90.6 MW; DEP NC = 78.5 MW. Total NEM solar = 169.1 MW.

[171] 2020 DEC IRP, p. 230, Table C-4.

[172] Total Companies NEM solar capacity at end of 2021, per EIA 2021 NEM database (https://www.eia.gov/electricity/data/eia861m/#netmeter): DEC NC = 90.6 MW; DEC SC = 92.3 MW; DEP NC = 78,5 MW; DEP SC = 19.8 MW. NC NEM solar = 169.1 MW; Total NEM solar = 281.2 MW. Carbon Plan, App. G, p. 18, Table G-7: current NEM production = 493,343 MWh/yr. Table G-8: new NEM production by 2030 = 697,707 MWh/yr. Therefore, total new NEM by 2030 (in MW) = 281.2 MW x (697,707 MWh/yr ÷ 493,343 MWh/yr) = 397.7 MW. New NC NEM by 2030 = (169.1 MW/281.2 MW) x 397.7 MW = 239 MW. Annual NC NEM additions, 2022-2030 (9 years) = 239 MW/9 years = 26.5 MW per year.

[173] The Carbon Plan NEM forecast is through 2030. The Carbon Plan forecast is extrapolated to 2035 to calculate expected additional NC NEM solar capacity in 2035. 26.5 MW per year x 14 years (2022-2035) = 371 MW.

[174] Ibid, p. 228. "For this IRP, DEC assumes that NEM tariffs will evolve to more closely align with the cost to serve rooftop solar customers, such that bill savings would gradually decrease over time."

XI. Carbon Plan Does Not Explain How Projected Cost of Transmission Build-Out Was Derived or Assess Alternatives to Transmission Build-Out

A. Transmission Upgrades to Support Utility-Scale Solar and Wind Power Are High Cost

The transmission upgrades necessary to interconnect large volumes of (utility-scale) solar may not result in least-cost compliance with HB 951's carbon reduction goals.[175] These transmission upgrade costs reflect the Companies preference for solar projects to be located in the transmission-limited border region of eastern North Carolina and South Carolina where land costs are low.[176] Wholesale urban SPS can substitute for remote utility-scale solar and eliminate the transmission upgrade cost associated with remote utility-scale solar.

The transmission upgrade costs associated with specific utility-scale solar projects in DEC and DEP service territories are known, at least for the most recent tranche of projects to be procured under the Competitive Procurement of Renewable Energy process.[177, 178] As a result, the transmission cost that would be avoided by substituting that utility-scale solar capacity with wholesale urban SPS connected at the distribution level can be calculated.

For example, DEC lists three solar projects in Laurens County, SC on contiguous 100 kV circuits with a combined capacity of 115 MW and a combined transmission upgrade cost of $40.55 million.[179] This is equivalent to a transmission upgrade cost of $0.35/watt.[180] This translates into

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[175] NCUC, 2022 Solar Procurement Proposal, Docket No. E-2, Sub 1297 and Docket No. E-7, Sub 1268, Initial Comments of the Public Staff, March 28, 2022, p. 4.

[176] Ibid, p. 7: "Stakeholders from the solar industry have emphasized the need to site solar capacity in DEP's southeastern service territory due to available land and lower land costs to solar developers. However, DEP's southeastern territory has significant transmission congestion because of the large amount of solar generation currently located in this area. The large quantities of new solar capacity in the interconnection queue in that area are already resulting in larger transmission upgrade costs compared to DEC. If solar capacity and the necessary transmission upgrades are built in DEP's territory to meet DEC's carbon reduction goals, current cost allocation methodologies could cause the costs to be largely recovered from DEP customers."

[177] Ibid., p. 2: "On March 14, 2022, the Companies filed their Petition proposing a system-wide solar procurement request for proposal (RFP), which would seek to competitively procure a minimum of 700 megawatts (MW) of utility-owned and third-party solar capacity, after preliminary analysis in advance of the Companies' 2022 Carbon Plan (2022 Solar RFP)."

[178] Ibid, p. 7, footnote 4: "DEC and DEP's Transition Cluster Study Phase 1 results under Generator Interconnection Information, Generator Study, Transition Cluster folder. DEC: https://www.oasis.oati.com/duk/; DEP: https://www.oasis.oati.com/cpl/."

[179] Duke Energy Carolinas, LLC, *Transitional Cluster Study Phase 1 Report*, February 28, 2022, pp. 4-5 and pp. 10-11, available at https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022-02-28_DEC_TC_Phase_1_Study_Report.pdf. Projects are: ID126078 (40 MW), ID164382 (37.5 MW), and ID165980 (37.5 MW). The transmission upgrade costs are $20.14 million, $5.03 million, and $19.38 million, respectively, a total of $44.55 million (p. 11). In addition, these three solar projects may collectively require an Optical Ground Wire (OPGW) upgrade at a cost of $77.498 million (pp. 4-5).

[180] $44,550,000 ÷ 115,000,000 watts = $0.353/watt.

a transmission upgrade cost adder of $35/MWh, as shown in Table 12. Individual solar projects have transmission upgrade costs as high as $0.52/watt.[181] In contrast, the Carbon Plan assumes all solar installed through 2026 has an associated transmission upgrade cost of $0.17/watt.[182]

The cost-effectiveness of wholesale urban SPS is relatively greater when compared to alternatives with high transmission upgrade costs, specifically offshore wind. The Carbon Plan estimates the transmission upgrade cost of the first 800 MW of offshore wind at $0.45/watt. The transmission upgrade cost of the second 800 MW of offshore wind is estimated at $0.79/watt. There would be no transmission upgrade costs associated with wholesale urban SPS located on the distribution grid at or near the loads being served.

Table 12. Calculation of DEC avoided transmission expenditure if wholesale urban solar is substituted for utility-scale solar

Element	Calculation	Value
Transmission upgrade costs estimated by DEC for 115 MW of utility-scale solar capacity (three projects) in Laurens County, SC	--	$44.55 million
Annualized cost recovery factor for new DEC transmission[183]	--	0.1349
Annualized transmission upgrade cost	0.1349 x $44.55 million	$6.01 million/yr
Annual solar production at 1,500 kWh/kW_{ac}	115 MW x 1,500 MWh/MW	172,500 MWh/yr
Cost adder of transmission upgrade	$6.01 millon/yr ÷ 172,500 MWh/yr	$35/MWh

DEC also indicates it may require Optical Ground Wire (OPGW) communications for utility-scale solar generators utilizing a DEC transmission circuit.[184] DEC estimates the OPGW upgrade cost for the 115 MW cluster of Laurens County, SC solar projects at $77.498 million.[185] The Carbon Plan transmission adder for utility-scale solar projects is far too low to have included OPGW.

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[181] ID165980: $19.38 million ÷ 37.5 MW = $0.52/watt.

[182] App. E, p. 39, Table E-44: Generic Transmission Network Upgrade Costs [2022 $/W].

[183] NCWARN *et al.*'s Initial Comments in NCUC Docket No. E-100, Sub 180, Attachment B, *Deployment of NEM Solar Allows Duke Energy to Eliminate New Transmission That Would Otherwise Be Built*, Table 4, p. 5. The annualized transmission cost recovery factor of 0.1349 is calculated from the known annualized cost of $254 million per year for the $1.883 billion San Diego Gas & Electric 500 kV Sunrise Powerlink transmission line ($254 million/yr ÷ $1,833 million = 0.1349/yr).

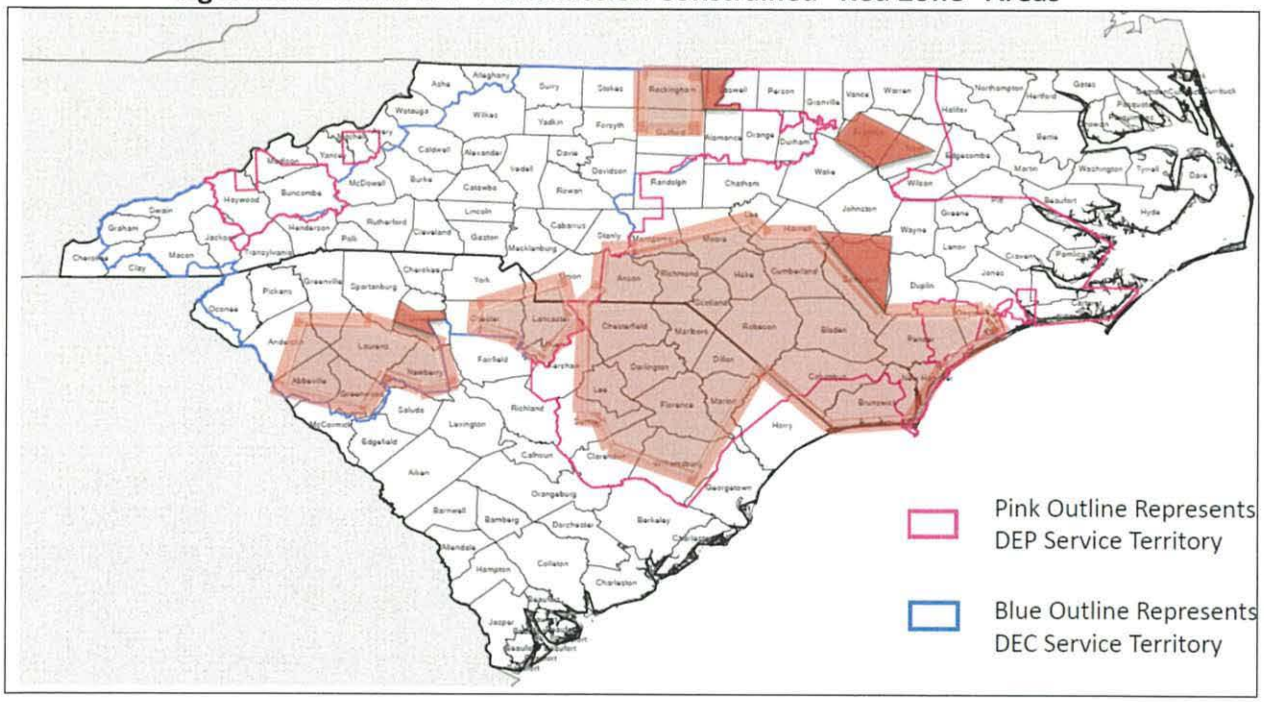
[184] Duke Energy Carolinas, LLC, *Transitional Cluster Study Phase 1 Report*, February 28, 2022, p. 17, available at https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022-02-28_DEC_TC_Phase_1_Study_Report.pdf.

[185] Ibid, pp. 4-5.

The Public Staff expresses concern, regarding the Companies' 2022 Solar Procurement Proposal, that the uncertain cost of transmission upgrades necessary to interconnect large volumes of (utility-scale) solar may not result in least-cost compliance with HB 951's carbon reduction goals.[186] These transmission upgrade costs reflect project developer preference to locate these projects in transmission-limited rural areas where land costs are low.[187]

This 2022 solar procurement the first tranche of solar procurement specified in HB 951. The proposed solar projects are overwhelmingly located in counties, identified in Figure 9, as transmission constrained by the Companies.[188] The Carbon Plan identifies this area as the "red zone."[189] The Laurens County solar projects are an example of the high cost of transmission upgrades needed to add more solar capacity in transmission constrained areas.

Figure 9. DEC and DEP Transmission Constrained "Red Zone" Areas[190]



[186] NCUC, 2022 Solar Procurement Proposal, Docket No. E-2, Sub 1297 and Docket No. E-7, Sub 1268, Initial Comments of the Public Staff, March 28, 2022, p. 4.

[187] Ibid, p. 7: "Stakeholders from the solar industry have emphasized the need to site solar capacity in DEP's southeastern service territory due to available land and lower land costs to solar developers. However, DEP's southeastern territory has significant transmission congestion because of the large amount of solar generation currently located in this area. The large quantities of new solar capacity in the interconnection queue in that area are already resulting in larger transmission upgrade costs compared to DEC. If solar capacity and the necessary transmission upgrades are built in DEP's territory to meet DEC's carbon reduction goals, current cost allocation methodologies could cause the costs to be largely recovered from DEP customers."

[188] See: https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/CPRE_Tranche_2_DEC_and_DEP_Constrained_Areas.pdf.

[189] App. P, p. 2.

[190] Ibid.

Reliance on wholesale rooftop and parking lot SPS in the Carbon Plan would largely eliminate transmission upgrades that would otherwise be necessary to interconnect utility-scale solar proposed in areas of the state with inadequate transmission capacity.

B. There Are Far Less Transmission Cost Impacts with Smaller (< 5 MW) Arrays Connected at the Distribution Level

The Carbon Plan is correct to point out that the historic pattern in the Carolinas of building smaller 5 MW utility-scale solar arrays, interconnected at the distribution level, has allowed the incorporation of over 4,000 MW of solar capacity with little utility upgrade expense. The Companies state:[191]

> Of the 4,350 MW of solar connected today, over 95% of installed solar projects are smaller, distribution-tied projects . . .
>
> One of the key barriers to adding resources, particularly solar, to the system is increasing transmission network upgrades required to interconnect new resources.

The one justification used by the Companies for shifting to large, transmission-dependent utility-scale solar arrays is the improved efficiency of the solar production. The Companies note that the existing, distribution grid connected projects have efficiencies in the range of 23 percent, while the larger proposed arrays would use bifacial panels and single-axis tracking to improve efficiency to 28 percent.[192]

There is no acknowledgement in the Carbon Plan that smaller projects can also use bifacial panels and single-axis tracking in the future, negating the implied advantage of larger, transmission-connected solar projects. There is also no comment on the fact that the higher cost of bifacial solar panels largely offsets the increased solar production.[193] Finally, solar project economies-of-scale are not addressed in the Carbon Plan. A distribution grid-connected 5 MW solar array with bifacial solar panels and single-axis tracking in the same location would have the same 28 percent efficiency as the Companies assert for the 75 MW solar arrays modeled in the Carbon Plan. The major cost advantage of interconnection at the distribution level is the avoidance of substantial transmission upgrade costs.

The economies-of-scale are realized for solar projects. Figure 10 is an NREL comparison of the cost elements of a 200 kW commercial rooftop solar array and a 100 MW single-axis tracking solar array. There is essentially no difference in the $/watt cost of the hardware and installation

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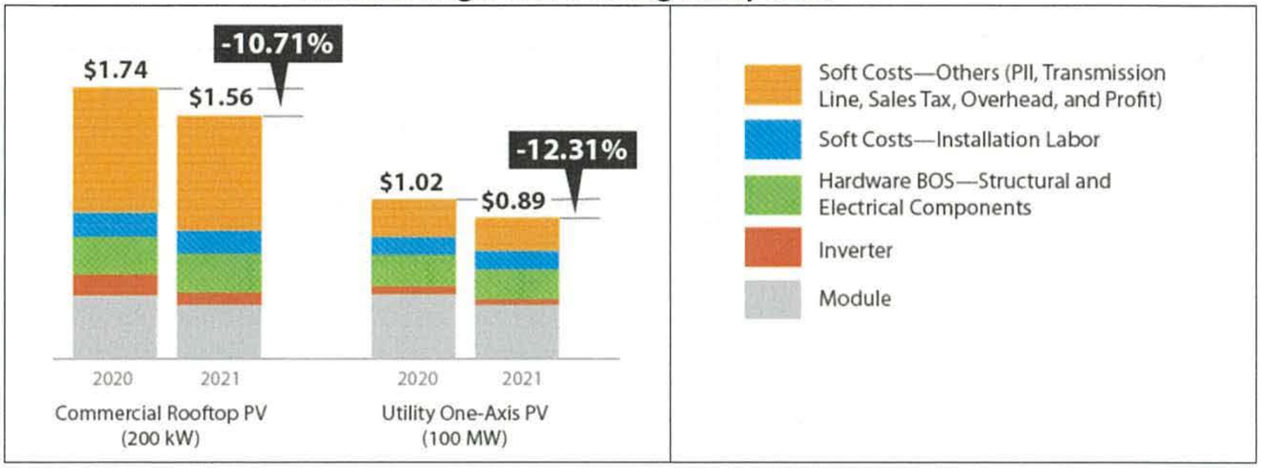
[191] App. I, p. 1.
[192] Ibid, p. 2
[193] Reuters, *U.S. Solar tariffs bolster growing dominance of bifacial panels*, March 16, 2022: https://www.reutersevents.com/renewables/solar-pv/us-solar-tariffs-bolster-growing-dominance-bifacial-panels.

labor between the two projects. The cost difference is in the level of effort (soft costs – orange) required by solar installation firms to secure individual commercial rooftop projects compared to a single 100 MW utility-scale project. However, the Companies have the capability to aggregate hundreds of rooftops and substantially reduce the soft costs associated with wholesale urban projects.

Figure 10. NREL comparison of solar cost elements, 200 kW commercial rooftop and 100 MW single-axis tracking utility-scale[194]



C. There Is No Transmission Upgrade Cost Associated with Commercial/Industrial Building Wholesale Rooftop and Parking Lot Solar

The Companies have tremendous, and largely untapped, commercial/industrial building wholesale rooftop and parking lot solar potential and urban undeveloped land potential available for the development of wholesale SPS projects. North Carolina has a solar rooftop and parking lot solar potential of 38,000 MW.a[195] The state has an undeveloped urban land wholesale SPS potential of 43,000 MW.[196] There is ample solar potential to meet the Carbon Plan reduction targets with projects that tie into the local distribution grid and predominantly serve local demand.

There are no transmission constraints to the wholesale urban SPS installation rate. The Companies have imposed a 750 MW per year solar expansion restriction due to transmission constraints.[197] The Companies project they can increase the solar interconnection pace to 1,800

[194] NREL, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2021*, November 4, 2021: https://www.nrel.gov/news/program/2021/new-reports-from-nrel-document-continuing-pv-and-pv-plus-storage-cost-declines.html.

[195] B. Powers – Powers Engineering, *NC Clean Path 2025*, Table 25, p. 57.

[196] Ibid.

[197] Chp. 2, p. 19. Table 2-10: Maximum Solar [MW] Allowed to Connect Annually.

MW per year by 2030 in Portfolio 1.[198] Prioritizing wholesale urban SPS would eliminate transmission constraints on the solar build-out toward carbon-free power.

One U.S. investor-owned utility has built a large-scale aggregated warehouse rooftop project selling wholesale power over the distribution grid. In March 2008, Southern California Edison (SCE) proposed to build 250 MW of solar on warehouse rooftops in urban Southern California. The project involved aggregating a large number of 1 MW to 2 MW rooftop projects. The California Public Utilities Commission ultimately approved a larger 500 MW SCE warehouse rooftop solar project in June 2009, stating:[199]

> Unlike other generation resources, these (large-scale rooftop solar) projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts.

The genesis for the focus on warehouse rooftops was former Gov. Arnold Schwarzenegger. He explained the basis for his advocacy of warehouse rooftop solar in a speech to EPA personnel as he was leaving the governor's office in late 2010:[200]

> I always said that I want to fly over California with the helicopter one day and just see not rooftops but see just solar on top of rooftops just to blanket it . . . because we have so much warehouse, so many warehouses, so much warehouse rooftops in California, we should blanket them. And now they are doing that.
>
> You can have all the renewable energy in the Mojave Desert but you still need to build transmission lines to bring it in . . . But if you have it on the rooftops of those warehouses it goes right to the grid and you don't even have to build the transmission lines.

The CEO of SCE, John Bryson, was an advocate for the warehouse rooftop solar project, explaining how it benefitted the SCE grid:[201]

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[198] Ibid, p. 17.

[199] CPUC press release, *CPUC Approves Edison Solar Roof Program* (June 18, 2009), available at https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/NEWS_RELEASE/102580.PDF.

[200] EPA press release, *Governor Schwarzenegger honored with EPA's Climate Change Champion Award*, December 2, 2010: https://archive.epa.gov/epapages/newsroom_archive/newsreleases/a90a6d9e480abd14852577ed00741e9e.html; complete speech (Vote Smart): https://justfacts.votesmart.org/candidate/public-statements/29556/arnold-Schwarzenegger.

[201] SCE press release, *Southern California Edison Launches Nation's Largest Solar Panel Installation*, March 27, 2008: https://newsroom.edison.com/releases/southern-california-edison-launches-nations-largest-solar-panel-installation.

"These new solar stations, which we will be installing at a rate of one megawatt a week, will provide a new source of clean energy, directly in the fast-growing regions where we need it most," said Bryson.

The focus on warehouse rooftops lost its champion when Gov. Schwarzenegger left office. SCE installed about 100 MW of warehouse rooftop solar before the program was subsequently modified to convert the remaining capacity to remote, transmission-dependent solar projects.[202] It is reasonable to assume that, had the warehouse rooftop program retained support at the highest levels of state government, there would now be 1,000s of MW of warehouse rooftop solar in California and substantially less pressure to build new renewable energy transmission lines to remote sites.

D. The Companies Can Earn Revenue Building Rooftop and Parking Lot Solar Plus Battery Storage, Just as They Can Building Utility-Scale Solar and Transmission Lines

The Companies own one of the largest commercial and industrial rooftop solar companies in the country, REC Solar.[203] Dominion Energy, owner of investor-owned utilities in North Carolina and South Carolina also owns BrightSuite, Inc.[204] BrightSuite offers solar and battery storage for Dominion Energy residential and commercial customers in Virginia.[205] There is no business impediment to the Companies earning revenue from wholesale urban SPS, either as direct owners or through power purchase agreements signed with subsidiaries like REC Solar, as a lower-impact alternative, from a cost and environmental standpoint, to major utility-scale solar and associated transmission line development in the "red zone."

XII. Carbon Plan Does Not Address the Environmental Impacts of Generation Mix or Transmission Build-Out

The Carbon Plan does not address the environmental impacts of 75 MW solar arrays, or much larger 200 MW to 300 MW solar arrays,[206] on environmental justice communities in the North Carolina and South Carolina countryside. Ground-mounted solar arrays conservatively require

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[202] CPUC, D.16-06-044, *Decision Granting (SCE) Petition for Modification and to Terminate the Solar Photovoltaic Program*, June 23, 2016: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K022/164022163.PDF.
[203] Duke Energy, Solar Energy (webpage), accessed July 4, 2022: https://www.duke-energy.com/our-company/about-us/businesses/renewable-energy/solar-energy." Duke Energy owns REC Solar, a provider of rooftop and ground-mounted solar, storage and microgrid systems for commercial-scale customers in the retail, manufacturing, agriculture, technology, government and nonprofit sectors. Based in San Luis Obispo, Calif., REC Solar offers easy customer financing, including leases and power purchase agreements."
[204] BrightSuite, Inc. homepage, accessed July 4, 2022: https://brightsuite.com/.
[205] Dominion Energy press release, *Dominion Energy makes rooftop solar easier, more affordable for Virginia residents*, June 21, 2022: https://news.dominionenergy.com/2022-06-21-Dominion-Energy-makes-rooftop-solar-easier,-more-affordable-for-Virginia-residents.
[206] App. I, p. 4. "If the size of the (solar) projects procured trends higher than in the past (e.g., 200 to 300 MW projects or larger), then the Companies will be more likely to exceed the annual targeted amounts."

about 10 acres of land per MW of capacity.[207] A 75 MW solar array and access infrastructure would cover 750 acres, more than one square mile of rural land.[208] 200 MW of solar would cover about three square miles, and a 300 MW array more than four square miles.
To put the size of these solar arrays in perspective, downtown Raleigh is 754 acres in area, or 1.18 square miles.[209] Each 75 MW solar building block that the Carbon Plan models would cover the area of downtown Raleigh. The target for solar additions in Carbon Plan Portfolio 1 is 5,400 MW of new solar by 2030, and 11,850 MW by 2035.[210] That translates into seventy-two (72) new downtown Raleigh equivalents by 2030 dedicated to solar production.[211] By 2035 there would be one hundred sixty-eight (168) new downtown Raleigh equivalents that are dedicated to solar production.

XIII. Distributed Generation Counter Proposal - Prioritize SPS, End Coal Usage, No New Gas, and No New Nuclear

The DG Counter Proposal relies on distributed SPS to phase out coal and avoid new gas and nuclear additions. It is constructed to achieve 100 percent carbon-free electricity by 2035.[212] The primary elements of the DG Counter Proposal are: 1) averaging 2,000 MW per year of wholesale urban SPS on commercial and industrial buildings and parking lots, large undeveloped urban parcels, and brownfields, 2) adding 4 hours of battery storage to the 8,000 MW of utility-scale solar in operation in North Carolina, 3) shutting down coal-only units by 2024 and operating dual fuel gas/coal units only on natural gas until retirement in 2035, and 4) converting nuclear units to synchronous condensers in the post-2035 timeframe to provide grid voltage support. The DG Counter Proposal is summarized in Table 13.

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[207] Great Plains Institute, *The True Land Footprint of Solar Energy*, September 14, 2021: https://betterenergy.org/blog/the-true-land-footprint-of-solar-energy/. "A conservative estimate for the footprint of solar development is that it takes 10 acres to produce one megawatt (MW) of electricity. This estimate accounts for site development around the solar arrays, including for maintenance and site access."
[208] There are 640 acres per square mile.
[209] City of Raleigh, *The 2030 Comprehensive Plan for the City of Raleigh – Downtown Raleigh*, as amended November 16, 2021, p. 15-2: https://user-2081353526.cld.bz/2030ComprehensivePlanUpdate/VI/.
[210] Chp. 3, p. 20. Table 3-3: Summary of Portfolio Results.
[211] 5,400 MW ÷ 75 MW = 72 solar arrays with downtown Raleigh equivalent area.
[212] This timeline is consistent with the executive order issued by President Biden on January 27, 2021 to address the climate crisis, which includes achieving a carbon-free electric power sector by 2035. See: The White House, *FACT SHEET: President Biden Takes Executive Actions to Tackle the Climate Crisis at Home and Abroad, Create Jobs, and Restore Scientific Integrity Across Federal Government*, January 27, 2021. See: https://www.whitehouse.gov/briefing-room/statements-releases/2021/01/27/fact-sheet-president-biden-takes-executive-actions-to-tackle-the-climate-crisis-at-home-and-abroad-create-jobs-and-restore-scientific-integrity-across-federal-government/.

Table 13. Elements of DG Counter Proposal

Element	2035 capacity, MW	2035 annual energy production, MWh
Wholesale urban SPS	25,000	38,000,000
Wholesale battery storage (4-hour at solar rated capacity)	28,000	112,000
Battery storage at existing utility-scale solar sites (4-hour at solar rated capacity)	8,000	32,000
Repurposing nuclear units as synchronous condensers	grid support	grid support

A. The Carbon Plan Portfolios Are Too Similar in Generation Mix

The Companies four Carbon Plan portfolios, Portfolios 1-4, are largely similar in content. The 2050 new capacity ranges of the generation technologies included in the four Carbon Plan base case portfolios and the four sensitivity "natural gas supply constraints" scenarios are provided in Table 14. The one portfolio with substantial levels of offshore wind power, 3,200 MW (base case) to 4,800 MW (sensitivity), is Portfolio 2. The two Portfolio 2 scenarios also have the lowest new solar, battery, and CT capacities among the portfolios.

Table 14. The capacity ranges of generation technologies across all base case and sensitivity portfolios[213]

Generation technology	2050 capacity range across all portfolios analyzed in the Carbon Plan, MW
Solar	17,700 – 19,900
Battery storage	5,300 – 7,400
Onshore wind	1,700 – 1,800
Offshore wind	0 – 4,800
Combined cycle (CC)	800 – 2,400
Combustion turbine (CT)	6,400 – 10,900
Nuclear	9,900 – 10,200
Pumped storage	1,700 (same in all portfolios)

[213] App. E, p. 77, Table E-71: Final Resource Additions by Portfolio [MW] for 2050; and p. 86, Table E-84: Final Resource Additions by (Alternative Fuel Supply Sensitivity) Portfolio [MW] for 2050.

The Companies' Carbon Plan strategy in the 2035 to 2050 period is fundamentally: 1) to replace retiring CTs with new CTs at approximately a 1:1 ratio and 2) to replace retiring nuclear units with new nuclear units at approximately a 1:1 ratio. Table 15 compares the proposed CT and nuclear additions in the 2035 to 2050 period in the Carbon Plan portfolios to the projected CT and nuclear retirements in the same period.

The Companies' nuclear fleet, eleven units, have license expiration dates ranging from 2030 to 2046. However, the Companies announced In September 2019 their intent to pursue Subsequent License Renewal (SLR) for the eleven existing nuclear units in their nuclear fleet.[214] The SLRs will extend the operating licenses for another 20 years.[215] That the SLRs will be approved is a base case assumption in the Carbon Plan.[216] What this means in practical terms is that the Companies would effectively double their nuclear capacity by 2050, from about 10,000 MW to about 20,000 MW, with the existing nuclear units then retiring permanently at intervals between 2050 and 2066.[217] About half of the existing nuclear capacity would still be operational beyond 2060 under the SLR approvals, with the last existing nuclear unit (Harris Unit 1) retiring in 2066.[218]

Table 15. Addition of CC, CTs, and nuclear from 2035 to 2050 across the four base case portfolios[219]

Generation technology	2035 to 2050 range of proposed Carbon Plan additions, MW	The Companies' planned retirements, 2035 to 2050, MW
Combined cycle (CC)	0	3,022 (only 570 MW retired prior to Dec. 2047)
Combustion turbine (CT)	5,200 – 6,300	6,354 (includes Asheville 3 & 4, 370 MW)
Nuclear	9,300 – 9,600	0 (existing nuclear units will be relicensed for 20 more years, will retire between 2050 and 2066)

B. Elements of DG Counter Proposal

The DG Counter Proposal described and recommended herein combines accelerated deployment of SPS to facilitate the rapid phase-out of coal, and no new gas or new nuclear. Wholesale urban solar installations would be built on commercial and industrial rooftops,

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214 App. L, p. 3.
215 Ibid.
216 Ibid.
217 App. L, p. 4, Figure L-2: Total Nuclear Generation Lost if SLR is Not Approved.
218 Ibid.
219 App. E, p. 77, Table E-71: Final Resource Additions by Portfolio [MW] for 2050; and p. 86, Table E-84: Final Resource Additions by (Alternative Fuel Supply Sensitivity) Portfolio [MW] for 2050.

parking lots, available urban parcels with 1 MW+ solar potential, and brownfield sites. Battery storage, with a minimum of 4 hours of storage at the capacity of the paired solar array, would be paired with all new solar to assure the dispatchability of the solar resource and provide maximum resilience.

The solar potential in North Carolina on commercial rooftops, commercial parking lots, undeveloped large urban parcels, and brownfield (contaminated land) sites is about 67,000 MW (105,000 GWh per year).[220] This is two-and-a-half times the 25,000 MW of new solar capacity that would be needed – by itself with no additional renewable resources – to meet the 2050 carbon-free target in the Carbon Plan.[221] Of the 105,000 MW total, about 18,600 MW (~30,000 GWh per year) is rooftop and commercial parking lot PV potential. Open parcels with at least 1 MW solar capacity potential and without restrictive uses in urbanized areas of North Carolina can provide up to 43,000 MW (68,000 GWh per year) of solar capacity. There is also approximately 5,000 MW (8,000 GWh per year) of additional PV that could be developed on contaminated land, known as brownfield sites, in North Carolina. The quantity and distribution of these solar resources are shown in Table 16.

Table 16. Estimate of North Carolina Local Solar and Brownfield PV Potential

Unit	Residential rooftop	Commercial/ industrial rooftop	Commercial parking lot	Undeveloped urban > 1 MW parcels	Brownfields	Total
MW	19,400	9,300	9,300	43,000	5,000	86,000
GWh/yr	30,600	14,700	14,700	68,000	8,000	136,000

A challenge in determining the quantities, in MW, of the elements of the DG Counter Proposal in North Carolina is that the Carbon Plan and the 2020 IRPs include DEP and DEC demand for both North Carolina and South Carolina. To address this challenge, the 2019 DEC and DEP retail sales of 96,399,570 MWh, from the EIA Electricity Profile for North Carolina, were used to approximate 2021 DEC and DEP demand in the state.[222] A conservative retail sales growth rate of 0.3 percent per year was assumed, consistent with the average of the 2010-2019 DEC and

[220] B. Powers – Powers Engineering, *North Carolina Clean Path 2025*, August 2017, p. 57:

[221] 1 MWac of installed fixed solar capacity in NC produces about 1,500 MWh per year of solar energy. There is approximately 8,000 MW of existing solar capacity in North Carolina, producing about 12,000,000 MWh per year. Therefore, sufficient new solar capacity to generate 38,000,000 MWh per year must be added. 38,000,000 MWh/yr ÷ 1,500 MWh/MW = ~25,000 MW.

[222] EIA, North Carolina Electricity Profile for 2019, Table 3. Top five retailers of electricity, with end use sectors, 2019, November 2, 2020. Combined DEC + DEP retail sales = 96,399,570 MWh.

DEP actual retail sales growth rates, to estimate combined 2035 DEC and DEP retail sales in North Carolina of 100,800,000 MWh.[223,224,225]

The 2020 DEC and DEP IRPs both state that about one-half of retail sales are met with nuclear power.[226] This means that about 50,000,000 MWh per year of non-nuclear carbon-free energy must be produced in 2035 to achieve a 100 percent clean energy target. About 12,000,000 MWh per year is already being produced by about 8,000 MW of existing solar installations in North Carolina.[227] Approximately 38,000,000 MWh of solar power would be required to "fill the gap." About 25,000 MW of new solar capacity would need to be installed in North Carolina by 2035 to provide this amount of solar energy.[228] This would require about 100,000 MWh of new battery storage to largely eliminate solar production curtailments and assure dispatchability, especially in spring and fall when demand is modest. This translates into about 25,000 MW of new 4-hour battery storage capacity.

The cost of the DG Counter Proposal will be less than the cost of Carbon Plan Portfolios 1-4, if the Companies take a leadership role in identifying and developing the wholesale urban SPS projects as their counterpart SCE did with its aggregated warehouse rooftop solar project.[229] The primary cost benefit of the DG Counter Proposal is to eliminate the high transmission build-out costs that will be necessary if the solar capacity is concentrated in the "red zone" as proposed in the Carbon Plan. The prioritization of wholesale urban SPS, which interconnects at the distribution level to serve local loads and not at the transmission level, would avoid the 750 MW annual transmission interconnection limitation on solar projects in the Carbon Plan.

1. Early Phase-Out of Coal Usage

All currently operational coal-only units will be permanently phased out in 2024 as a component of the DG Counter Proposal. The dual fuel gas/coal units will continue to produce

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[223] 96,399,570 MWh x $(1.003)^{15}$ = 100,829,843 MWh. The assumption of any demand growth at all is conservative, given that from 2016 through 2021 retail sales showed no growth in DEC territory and declined at a rate of -0.7% in DEP territory. See Carbon Plan, App. F, p. 16, Table F-14: Electricity Sales (GWh) – DEC, and App. F, p. 17, Table F-15: Electricity Sales (GWh) – DEP.

[224] In the DG Counter Proposal, it is anticipated that EV adopters will largely also be NEM customers and use NEM solar to offset EV charging loads.

[225] DEC and DEP customers are predominantly electric or exclusively electric now. Ongoing building electrification may cause little upward on building electricity demand as lower efficiency electric equipment is replaced with higher efficiency equipment over time.

[226] *E.g.*, DEC's 2020 IRP, p. 75.

[227] Solar Energy Industries Association, *State Solar Spotlight – North Carolina*, June 7, 2022: https://www.seia.org/sites/default/files/2022-06/North%20Carolina%20Solar-Factsheet-2022-Q2.pdf. Annual production from a fixed solar array in North Carolina is about 1,500 kWh/yr/kWac (1,500 MWh/yr/MWac). Therefore, 8,000 MW x 1,500 MWh/MWac = 12,000,000 MWh per year.

[228] 38,000,000 MWh/yr ÷ 1,500 MWh/MW = 25,333 MW.

[229] Supra, Section XI. C, p. 43.

up to 2,600 MW of output on natural gas only. This will be achieved by: 1) permanently switching Cliffside Unit 6 to 100 percent natural gas in 2022, 2) Belews Creek's two 1,100 MW units have been retrofit to burn 50 percent natural gas, collectively producing up to 1,100 MW on natural gas only, and 3) Marshall Units 3 and 4 have been retrofit to burn 50 percent natural gas, and collectively can produce 640 MW on natural gas only.

The Companies are running excessively high reserve margins. At least 3,000 MW of coal capacity could be retired immediately while maintaining a 17 percent PRM. In addition, ample supply of firm and non-firm imports are available from adjacent balancing authorities. There is nearly 50,000 MW of low-cost merchant capacity in the PJM Interconnection regional market,[230] with substantial available capacity,[231] adjacent to DEC and DEP territories. Some of this capacity could be contracted by the Companies on a firm bilateral seasonal basis, specifically in winter when neighboring balancing authorities have excess capacity, to address any near-term winter reserve margin shortfalls. Rapid deployment of battery storage capacity will quickly eliminate any reserve margin justification for seasonal firm imports in winter.

A major advantage to this approach would also be to lower costs to Duke Energy ratepayers. The cost of production of Duke Energy's "coal only" plants is $58/MWh (Roxboro) and $90/MWh (Mayo).[232] These production costs are significantly higher than those of small commercial solar rooftop projects at $44/MWh,[233] or the cost of production of CC plants at about $30/kWh (when natural gas prices are low).[234]

2. Prioritize Wholesale Urban SPS

Wholesale urban SPS installations would be built on commercial and industrial rooftops, associated parking lots, available urban parcels with solar potential generally greater than 1 MW, and brownfield sites. The anticipated capacity of individual projects would be from 500 kW to 5 MW. The target installation rate would be 2,000 MW per year. This is incrementally higher than the actual solar installation rate already achieved in North Carolina. 1,250 MW of

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[230] Monitoring Analytics, LLC, *2019 Quarterly State of the Market Report for PJM: January through March*, May 9, 2019, p. 65. See: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019q1-som-pjm.pdf. As of March 31, 2019, there was 47,591.6 MW of operational combined cycle capacity in PJM.
[231] U.S. Energy Information Administration, *Natural gas-fired power plants are being added and used more in PJM Interconnection*, October 17, 2018. See: https://www.eia.gov/todayinenergy/detail.php?id=37293. Combined cycle units in PJM generated about 200 million MWh in 2017, at an average capacity factor of about 60 percent.
[232] DEP, 2020 FERC Form 1, April 15, 2021, p. 402.1 (Roxboro, $0.0538/kWh) and p. 403 (Mayo, $0.0897/kWh).
[233] NREL, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020*, January 2021, p. 102, Attachment B [Commercial Rooftop (200 kW), High resource (CF 20.4%), ITC, $0.049/kWh, ITC; NREL press release, *New Reports From NREL Document Continuing PV and PV-Plus-Storage Cost Declines*, November 12, 2021: https://www.nrel.gov/news/program/2021/new-reports-from-nrel-document-continuing-pv-and-pv-plus-storage-cost-declines.html. Commercial rooftop solar, 10.7 percent decline, Q1 2020 to Q1 2021.

solar of was installed in North Carolina in 2017, and the state averaged more than 1,000 MW per year of solar from 2015 through 2019.[235]

The anticipated capacity range of wholesale urban SPS projects, 500 kW to 5 MW, is also consistent with the capacity of most existing North Carolina solar projects. These existing projects are generally 5 MW or less and interconnected at the distribution level.[236]

3. Retrofit Battery Storage to 8,000 MW of Existing Utility-Scale Solar

A least-cost clean peaking power alternative for the Companies is to retrofit battery storage to the nearly 8,000 MW of existing solar facilities in North Carolina as a substitute for the proposed new gas-fired capacity.[237] This existing solar capacity is already deliverable on existing transmission lines. Locating battery storage at the existing solar sites would minimize solar curtailments, make the solar power fully dispatchable, and allow expansion of solar development on those same circuits.

Duke Energy has been directed by the NCUC to work with stakeholders to enable retrofitting battery storage at existing solar sites in North Carolina.[238] The NCUC has acknowledged that energy storage is a cost-competitive option, and that "energy storage will play a significant role in enabling a more affordable, reliable, and sustainable electricity system."[239]

The workshop stakeholders reached consensus on numerous key areas associated with adding storage to existing solar facilities.[240] Fundamentally, the NCUC is already moving in the direction of retrofitting battery storage at existing solar sites as an alternative to adding more gas-fired capacity.[241]

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[235] Solar Energy Industries Association, *State Solar Spotlight – North Carolina*, June 7, 2022: https://www.seia.org/sites/default/files/2022-06/North%20Carolina%20Solar-Factsheet-2022-Q2.pdf.

[236] App. I, p. 6. "One of the major evolving factors that will influence the achievable amount of MW of interconnections is the size of the solar projects procured under HB 951. As the Commission is aware, the State incented a truly unparalleled amount of 5 MW and smaller utility-scale solar generation that required interconnection to the distribution system. As explained in prior proceedings, the Companies' nation-leading solar historic interconnection success is even more remarkable given that such outcomes required interconnection of hundreds of distribution-connected utility-scale projects."

[237] Solar Energy Industries Association, *State Solar Spotlight - North Carolina*, webpage accessed February 21, 2021: https://www.seia.org/sites/default/files/2020-12/North%20Carolina.pdf. Total installed solar in North Carolina at end of Q3 2020 (September 30, 2020) = 6,487 MW.

[238] DEC's IRP, p. 118. "Also, as directed by the NCUC, the Company has been working with stakeholders to assess challenges and develop recommendations to address challenges related to retrofit of existing solar facilities with energy storage. A report on this matter is expected to be filed in September 2020."

[239] NCCEBA, NCSEA, SELC, *Reply Comments, Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018 NCUC Docket No. E-100, Sub 158*, November 20, 2020, pp. 1-2.

[240] NCCEBA, NCSEA, SELC, Reply Comments, *supra*, p. 13.

[241] Ibid, p. 10. "The solar-plus-storage resource can help avoid the cost of expensive new peaking capacity, . ."

4. Convert Nuclear Units to Synchronous Condensers for Voltage/Grid Support

One common concern with a renewable energy grid with thousands of smaller generation sources is the lack of large spinning generators with a great deal of mass, such as those found at large nuclear and coal plants, to serve as anchors to maintain grid voltage in the proper range. One alternative to assure this function is met without continuing to operate the coal or nuclear units is to operate synchronous condensers at the site(s).[242] The synchronous condenser acts like a spinning unpowered electric motor. The rotational speed of the synchronous condenser is maintained by grid power, and not the coal or nuclear unit. Converting the coal or nuclear unit generator(s) to serve as stand-alone synchronous condensers is a potential way to utilize existing hardware at these sites to support a full renewable energy build-out.

IXV. Conclusion

All currently operational "coal-only" coal units can be permanently phased out, with other coal units limited to natural gas firing only, by 2024. Firing coal is unnecessary to assure reliability with the available supply mix. The Companies are maintaining excessive PRMs. At least 3,000 MW of coal capacity can be retired while still maintaining the target PRM of 17 percent. Neighboring balancing areas, especially PJM, also have excess reserves and ample generation capacity reliably available in winter to substitute for Duke Energy coal power.

This report describes a DG Counter Proposal portfolio. The combination of solar power plus battery storage (SPS) is a lower-cost and more versatile alternative than CTs to meet peak and seasonal demand going forward. Wholesale urban SPS should replace the new CC, CT, remote utility-scale solar, wind, and nuclear capacity included in the Carbon Plan. Wholesale urban SPS can compete on cost with remote utility-scale solar/SPS with the leadership of the Companies. These projects will be interconnected at the distribution level to serve demand in the local area. They will eliminate the high cost of the transmission build-out, and transmission interconnection capacity limits, anticipated in the Carbon Plan. Battery storage should also be added at existing utility-scale solar sites to maximize the dispatchability of this solar power.

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[242] San Diego Gas & Electric News Center, Innovation Spotlight: SynCons (Synchronous Condensers), May 20, 2019: https://www.sdgenews.com/article/innovation-spotlight-syncons.

VERIFICATION

I, William E. Powers, pursuant to the Commission's *Order Establishing Additional Procedures and Requiring Issues Report* entered on April 1, 2022 in the above-referenced docket, hereby verify that the contents of the foregoing Report are true to the best of my knowledge and belief, except as to those matters stated on information and belief, and as to those matters, I believe them to be true.

This the 14 day of July, 2022.

William E. Powers

William E. Powers

Sworn to and subscribed before me,
this the ___ day of ___________, 2022.

SEE ATTACHED NOTARY FORM

____
Notary Public

My commission expires: ___________

JURAT

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document, to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document

State of California
County of San Diego

Subscribed and sworn (or affirmed) before me on this
14th Day of July, 2022, by
William E. Powers
proved to me on the basis of satisfactory evidence to be the person~~(s)~~ who appeared before me.

Notary's Signature

ELYCE M. DUNKLEBERGER
Commission No. 2342553
NOTARY PUBLIC - CALIFORNIA
SAN DIEGO COUNTY
Commission Expires January 20, 2025

OPTIONAL

DESCRIPTION OF ATTACHED DOCUMENT
Title of Type of Document: Verification
Document Date: 07/14/22 Number of Pages Including this One: 2
Additional Information:

Attachment 2

The Companies' Response to SELC's Data Request No. 2-12 in Docket No. E-100, Sub 165

SELC
NCUC DN E-100, Sub 165
PSCSC DN 2019-224-E & 2019-225-E
2020 DEC and DEP IRPs
Item No. 2-12

Note: These questions reference the Duke Energy Carolinas IRP ("DEC IRP") but are also applicable to Duke Energy Progress ("DEP"). They reference Appendix C Load Forecast, and all quotes, figure and table numbers, etc. are the same, only the DEP Appendix C Load Forecast pages numbers are 9 fewer (i.e. DEC p. 224 is DEP p. 215, etc. in Appendix C). The few references to the main IRP are the same page number (32, 36) in both IRP documents. To the extent that answers defer between DEC and DEP, please note the differences in your response.

Note: The SELC Request was received and labeled as "Second Data Request," and is the Second Set of Requests received from SELC. The Requests contained questions labeled 1-1, 1-2, etc. For clarity, DEC and DEP are providing responses labeled in alignment with these requests being the second set of requests (2-1, 2-2, etc.)

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

2-12. Reference DEC IRP p. 225: Identify in more detail the "refinements to peak history" that were identified "as a result of continuous improvement efforts." Provide any supporting analysis, reports, and workpapers.

Response:

See attached file labeled "DR 2-12.xlsx."

DR 2-12.xlsx

DEC

	Before		After	
Year	Winter	Summer	Winter	Summer
2012	15,962	17,933	15,962	17,933
2013	15,363	16,757	15,363	16,757
2014	19,232	17,397	18,275	16,501
2015	20,455	18,742	18,931	17,529
2016	18,213	19,119	17,073	18,037
2017	18,069	18,811	16,883	17,539
2018	19,436	18,008	19,077	17,779
2019	16,782	17,736	16,880	17,736

DEP

	Before		After	
Year	Winter	Summer	Winter	Summer
2012	11,826	13,405	11,440	12,912
2013	12,897	12,785	12,376	12,273
2014	14,993	12,663	14,453	12,497
2015	16,429	13,415	16,080	13,134
2016	13,801	13,578	13,357	13,296
2017	15,020	13,143	14,583	12,792
2018	16,016	13,403	15,897	13,029
2019	13,942	12,953	13,715	12,953

Description of refinements:

The refinements to peak history consists of updating the wholesale contracts in IRP Load, revised demand response program impacts and revised load history reports. Recent historical years were mostly impacted by demand response program and load history report updates (which are typical as studies and reconciliations are completed), while earlier historical years were impacted by updating wholesale contracts in IRP Load.

Attachment 3

The Companies' Response to NC WARN's Data Request No. 4-5 in Docket No. E-100, Sub 165

Question #: NCWARN DEC DR4-5

Question Detail: In response to NC WARN's Data Request No. 3-1, the Company identified several units that were "not operating at full capacity" during several dates occurring in 2018-2019 and identified on Figure 9-A (page 72) of the Company's 2020 Integrated Resource Plan. Please identify the output in MW (if any) for the units identified in response to NC WARN's Data Request No. 3-1 at peak time for the dates on which responsive information was provided. (For clarity, the present data request is intended to ascertain the extent to which the units identified in response to NC WARN's Data Request No. 3-1 were operating below full capacity, or alternatively, were not operational.)

Response: DEC is providing the requested information for the dates in the time period 2018-2019. Because the explanatory parenthetical in the request provides more clarity on the intent of the request, data for each date are separated into those units/groups that were online and those that were offline. In addition, it appears the intent is to determine the additional MW capability which could have served additional load. The actual capabilities of the units/groups for these dates and times are not the same as the stated Net Dependable Capacities. Ambient conditions (e.g., temperature, humidity, sun angle and cloud cover for solar resources) have a significant effect, positive or negative, on the actual capability of a given unit. For this reason, the available unloaded capability for each unit is provided although it was not actually requested. For offline units, this value is estimated actual capability.

Some additional explanation is needed to fully understand the meanings of the reasons given.

- Online
  - Constrained – unit(s) temporarily constrained during some part of the hour, e.g., unit ramping up from a previous outage
  - Forced Derate – unit(s) constrained to operate at a lower level due to failure or limitation of one or more subsystems
  - Reliability – unit(s) constrained to operate at a specified level or range to avoid violation of reliability constraints
  - Reserves – the unloaded capacity is spinning reserve used for regulation and to provide a portion of contingency reserves
- Offline
  - Contingency Reserve – quick start unit(s) needed to complete contingency reserve needs
  - Forced Outage – unit(s) undergoing repairs due to an unforeseen/unplanned issue
  - Maint Outage – unit(s) undergoing planned maintenance or testing
  - Minimal Sun – integrated solar aggregate for the hour did not provide an entire MWh because sunlight was not strong enough to meet minimum inverter operation
  - Out of Economics – unit cost high enough and demand low enough to preclude need to run this unit
  - Reserve - Fuel Mgmt – unit(s) held in reserve to conserve a limited fuel
  - Reserve Shutdown – units in cold shutdown because longer term forecasts (weeks/months) indicated units would not be needed during the period

Data is provided for peaks for the following dates in 2018-2019: 1/2/2018, 1/25/19, 1/31/19, 3/6/19, 1/5/18, 12/6/18, and 1/11/19. As with the NCWARN DR3-1 response, the reason why each unit/group was not operational is indicated by the Reason column. Some units have been ungrouped from the NCWARN DR3-1 listing since loadings and available capacity differ for those in the group. Additionally, the tables have columns labeled Loading and Available to show the actual integrated hourly loading in MW and the unloaded MW capacity up to the actual capability of the unit/group for the given hour.

- Reasons marked with an asterisk (*) indicate that the unit(s) was/were online for a part of the hour but tripped before the end of the hour; for these units the Available column does not show the amount actually available but the amount that could have been available if not for the trip.
- CONVENTIONAL HYDRO is a group of multiple units at several plants. Available capacity varies throughout the day and is somewhat less than the sum of the Net Dependable Capacities of these units due to outages and derates to meet licensing, environmental, testing, etc. requirements.

DEC Units/Groups Not Operational at Full Capacity at 01/02/18 Peak

Online Units/Groups

Unit/Group	Reason	Loading	Available
CONVENTIONAL HYDRO	Reserves	593	342
JOCASSEE PS	Reserves	770	10
LEE CT 07	Reserves	45	1
LINCOLN CT 02	Constrained	17	82
LINCOLN CT 04	Constrained	7	91
LINCOLN CT 09	Reserves	96	1
LINCOLN CT 10	Reserves	97	1
MILL CREEK CT 06	Reserves	89	3

Offline Units/Groups

Unit/Group	Reason	Loading	Available
3RD PARTY SOLAR	Minimal Sun	0	0
DUKE SOLAR	Minimal Sun	0	0
LEE STEAM 03	Maint Outage	0	173
LINCOLN CT 05	Contingency Reserve	0	97
LINCOLN CT 06	Contingency Reserve	0	97
LINCOLN CT 07	Contingency Reserve	0	98
LINCOLN CT 08	Contingency Reserve	0	98
LINCOLN CT 12	Forced Outage	0	98
LINCOLN CT 13	Contingency Reserve	0	98
MARSHALL 03	Forced Outage	0	658
ROCKINGHAM CT 01	Maint Outage	0	179

DEC Units/Groups Not Operational at Full Capacity at 01/25/19 Peak

Online Units/Groups

Unit/Group	Reason	Loading	Available
BAD CREEK PS	Reserves	1241	119
CLIFFSIDE 06	Forced Derate	645	204
CONVENTIONAL HYDRO	Reserves	523	192
JOCASSEE PS	Reserves	729	51
LEE CC PB1	Reserves	795	21
MARSHALL 01	Reserves	330	50
MARSHALL 02	Reserves	328	52
MARSHALL 04	Reliability	531	129
ROCKINGHAM CT 02	Reserves	178	2
ROCKINGHAM CT 03	Reserves	178	2
ROCKINGHAM CT 04	Reserves	178	2
ROCKINGHAM CT 05	Reserves	178	2

Offline Units/Groups

Unit/Group	Reason	Loading	Available
ALLEN 01	Reserve Shutdown	0	167
ALLEN 02	Reserve Shutdown	0	167
ALLEN 03	Reserve Shutdown	0	270
ALLEN 04	Reserve - Fuel Mgmt	0	267
ALLEN 05	Reserve Shutdown	0	259
BELEWS CREEK 01	Forced Outage	0	1110
BELEWS CREEK 02	Maint Outage	0	1110
CLIFFSIDE 05	Reserve - Fuel Mgmt	0	546
KEOWEE HYDRO	Maint Outage	0	0
LEE CT 07	Maint Outage	0	49
LEE CT 08	Maint Outage	0	49
LEE STEAM 03	Reserve Shutdown	0	160
LINCOLN CT 01	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 02	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 03	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 04	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 05	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 06	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 07	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 08	Contingency Reserve/Out of Economics	0	93

LINCOLN CT 09	Contingency Reserve/Out of Economics	0	91
LINCOLN CT 10	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 11	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 12	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 13	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 14	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 15	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 16	Contingency Reserve/Out of Economics	0	92
MARSHALL 03	Reserve Shutdown	0	658
MILL CREEK CT 01	Out of Economics	0	91
MILL CREEK CT 02	Out of Economics	0	90
MILL CREEK CT 03	Out of Economics	0	91
MILL CREEK CT 04	Maint Outage	0	90
MILL CREEK CT 05	Out of Economics	0	89
MILL CREEK CT 06	Out of Economics	0	86
MILL CREEK CT 07	Out of Economics	0	90
MILL CREEK CT 08	Out of Economics	0	90

<u>DEC Units/Groups Not Operational at Full Capacity at 01/31/19 Peak</u>

<u>Online Units/Groups</u>

Unit/Group	Reason	Loading	Available
ALLEN 05	Reliability	258	1
BAD CREEK PS	Reserves	1206	154
CLIFFSIDE 06	Reserves	841	8
CONVENTIONAL HYDRO	Reserves	567	50
JOCASSEE PS	Reserves	704	76
LEE CC PB1	Reserves	793	25
MARSHALL 01	Reserves	372	8
MARSHALL 02	Reserves	375	5
MARSHALL 03	Reliability	644	14
MILL CREEK CT 01	Reserves	85	8
MILL CREEK CT 02	Reserves	84	8
MILL CREEK CT 03	Reserves	85	7
ROCKINGHAM CT 01	Reserves	170	10
ROCKINGHAM CT 02	Reserves	163	17
ROCKINGHAM CT 03	Reserves	162	18
ROCKINGHAM CT 04	Reserves	167	13
ROCKINGHAM CT 05	Reserves	178	2

<u>Offline Units/Groups</u>

Unit/Group	Reason	Loading	Available
ALLEN 01	Reserve Shutdown	0	167
ALLEN 02	Reserve Shutdown	0	167
ALLEN 03	Reserve Shutdown	0	270
ALLEN 04	Reserve - Fuel Mgmt	0	267
CLIFFSIDE 05	Reserve - Fuel Mgmt	0	546
KEOWEE HYDRO	Maint Outage	0	0
LEE CT 07	Maint Outage	0	49
LEE CT 08	Maint Outage	0	49
LEE STEAM 03	Reserve Shutdown	0	160
LINCOLN CT 01	Contingency Reserve/Out of Economics	0	95
LINCOLN CT 02	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 03	Contingency Reserve/Out of Economics	0	95
LINCOLN CT 04	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 05	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 06	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 07	Contingency Reserve/Out of Economics	0	95
LINCOLN CT 08	Contingency Reserve/Out of Economics	0	95
LINCOLN CT 09	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 10	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 11	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 12	Contingency Reserve/Out of Economics	0	95
MILL CREEK CT 04	Out of Economics	0	92
MILL CREEK CT 05	Out of Economics	0	90
MILL CREEK CT 06	Out of Economics	0	88
MILL CREEK CT 07	Out of Economics	0	91
MILL CREEK CT 08	Out of Economics	0	92

<u>DEC Units/Groups Not Operational at Full Capacity at 03/06/19 Peak</u>

<u>Online Units/Groups</u>

Unit/Group	Reason	Loading	Available
BAD CREEK PS	Reserves	1019	341
CONVENTIONAL HYDRO	Reserves	472	256
JOCASSEE PS	Reserves	600	180
KEOWEE HYDRO	Reserves	80	72
LEE CT 07	Reserves	47	2
LEE CT 08	Reserves	48	1
MILL CREEK CT 01	Reserves	26	65
MILL CREEK CT 02	Reserves	25	65
MILL CREEK CT 03	Reserves	76	15
MILL CREEK CT 04	Reserves	75	16

ROCKINGHAM CT 02	Reserves	133	47
ROCKINGHAM CT 03	Reserves	170	10
ROCKINGHAM CT 05	Reserves	110	70

<u>Offline Units/Groups</u>

Unit/Group	Reason	Loading	Available
ALLEN 01	Reserve - Fuel Mgmt	0	167
ALLEN 02	Reserve - Fuel Mgmt	0	167
ALLEN 03	Maint Outage	0	270
ALLEN 04	Maint Outage	0	267
ALLEN 05	Reserve - Fuel Mgmt	0	259
BUCK CC PB1	Maint Outage	0	704
LEE STEAM 03	Reserve Shutdown	0	160
LINCOLN CT 01	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 02	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 03	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 04	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 05	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 06	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 07	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 08	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 09	Contingency Reserve/Out of Economics	0	91
LINCOLN CT 10	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 11	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 12	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 13	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 14	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 15	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 16	Contingency Reserve/Out of Economics	0	92
MARSHALL 02	Maint Outage	0	380
MARSHALL 03	Forced Outage	0	640
MARSHALL 04	Forced Outage	0	500
MILL CREEK CT 05	Out of Economics	0	89
MILL CREEK CT 06	Out of Economics	0	86
MILL CREEK CT 07	Out of Economics	0	90
MILL CREEK CT 08	Out of Economics	0	90
ROCKINGHAM CT 01	Out of Economics	0	180
ROCKINGHAM CT 04	Out of Economics	0	180

<u>DEC Units/Groups Not Operational at Full Capacity at 01/05/18 Peak</u>

Online Units/Groups [922 MW]

Unit/Group	Reason	Loading	Available
ALLEN 01	Reserves	143	13
ALLEN 03	Reliability	253	5
ALLEN 04	Reserves	250	8
ALLEN 05	Reserves	254	4
BAD CREEK PS	Reserves	883	477
BELEWS CREEK 02	Reserves	1102	8
CLIFFSIDE 05	Forced Derate	523	29
CONVENTIONAL HYDRO	Reserves	633	241
JOCASSEE PS	Reserves	710	70
LEE CT 07	Reserves	47	1
LEE CT 08	Reserves	47	1
LINCOLN CT 01	Reserves	97	1
LINCOLN CT 02	Reserves	97	2
LINCOLN CT 03	Reserves	96	3
LINCOLN CT 04	Reserves	97	1
LINCOLN CT 05	Reserves	96	1
LINCOLN CT 08	Reserves	97	1
LINCOLN CT 15	Reserves	96	2
MARSHALL 03	Forced Derate	632	36
MARSHALL 04	Reserves	654	11
ROCKINGHAM CT 01	Reserves	177	2
ROCKINGHAM CT 02	Reserves	178	1
ROCKINGHAM CT 03	Reserves	178	1
ROCKINGHAM CT 04	Reserves	178	1
ROCKINGHAM CT 05	Reserves	177	2

Offline Units/Groups [1,320 MW]

Unit/Group	Reason	Loading	Available
LEE STEAM 03	Out of Economics	0	168
LINCOLN CT 06	Contingency Reserve	0	97
LINCOLN CT 09	Contingency Reserve	0	97
LINCOLN CT 10	Contingency Reserve	0	98
LINCOLN CT 11	Contingency Reserve	0	98
LINCOLN CT 12	Contingency Reserve	0	98
LINCOLN CT 13	Contingency Reserve	0	98
LINCOLN CT 14	Contingency Reserve	0	97
LINCOLN CT 16	Forced Outage	0	97
MILL CREEK CT 01	Out of Economics	0	92
MILL CREEK CT 02	Out of Economics	0	92

MILL CREEK CT 03	Out of Economics	0	92
MILL CREEK CT 06	Out of Economics	0	92

DEC Units/Groups Not Operational at Full Capacity at 12/06/18 Peak

Online Units/Groups

Unit/Group	Reason	Loading	Available
ALLEN 03	Reliability	222	48
ALLEN 04	Reliability	238	29
BAD CREEK PS	Reserves	1159	201
BELEWS CREEK 01	Constrained	229	881
CLIFFSIDE 05	Maint Derate	401	4
CLIFFSIDE 06	Maint Derate	766	9
CONVENTIONAL HYDRO	Reserves	572	164
JOCASSEE PS	Reserves	690	90
LEE CT 07	Reserves	48	1
LEE CT 08	Reserves	47	2
MARSHALL 01	Reserves	307	73
MARSHALL 02	Reserve Shutdown	376	4
MARSHALL 03	Reliability	615	43
MARSHALL 04	Constrained	626	34
MILL CREEK CT 01	Reserves	89	2
MILL CREEK CT 02	Reserves	89	2
MILL CREEK CT 04	Reserves	90	1
ROCKINGHAM CT 01	Reserves	177	3
ROCKINGHAM CT 02	Reserves	179	1
ROCKINGHAM CT 03	Reserves	179	1
ROCKINGHAM CT 04	Reserves	179	1
ROCKINGHAM CT 05	Reserves	179	1

Offline Units/Groups

Unit/Group	Reason	Loading	Available
ALLEN 01	Maint Outage	0	167
ALLEN 02	Maint Outage	0	167
ALLEN 05	Maint Outage	0	259
BELEWS CREEK 02	Maint Outage	0	1110
CATAWBA NUCLEAR 01	Maint Outage	0	0
LEE CC PB1	Forced Outage	0	817
LEE STEAM 03	Maint Outage	0	160
LINCOLN CT 01	Contingency Reserve	0	93

LINCOLN CT 02	Contingency Reserve	0	92
LINCOLN CT 03	Contingency Reserve	0	94
LINCOLN CT 04	Contingency Reserve	0	93
LINCOLN CT 06	Contingency Reserve	0	92
LINCOLN CT 09	Contingency Reserve	0	92
LINCOLN CT 10	Contingency Reserve	0	92
LINCOLN CT 11	Contingency Reserve	0	93
LINCOLN CT 12	Contingency Reserve	0	94
LINCOLN CT 13	Contingency Reserve	0	94
OCONEE NUCLEAR 01	Maint Outage	0	0

DEC Units/Groups Not Operational at Full Capacity at 01/11/19 Peak

Online Units/Groups

Unit/Group	Reason	Loading	Available
CLIFFSIDE 05	Reliability	543	3
BAD CREEK PS	Reserves	1351	9
JOCASSEE PS	Reserves	765	15
LEE CT 07	Reserves	48	1
LEE CT 08	Reserves	47	2
LEE CC PB1	Reserves	776	41
CONVENTIONAL HYDRO	Reserves	606	158
MILL CREEK CT 02	Constrained	71	20
MILL CREEK CT 01	Constrained	70	22

Offline Units/Groups

Unit/Group	Reason	Loading	Available
ALLEN 01	Reserve - Fuel Mgmt	0	167
ALLEN 02	Reserve - Fuel Mgmt	0	167
ALLEN 03	Reserve - Fuel Mgmt	0	270
ALLEN 04	Reserve - Fuel Mgmt	0	267
ALLEN 05	Reserve - Fuel Mgmt	0	259
BELEWS CREEK 01	Reserve - Fuel Mgmt	0	1110
CLIFFSIDE 06	Forced Outage	0	849
DUKE SOLAR	Minimal Sun	0	0
LEE STEAM 03	Reserve Shutdown	0	160
LINCOLN CT 01	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 02	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 03	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 04	Contingency Reserve/Out of Economics	0	93

LINCOLN CT 05	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 06	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 07	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 08	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 09	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 10	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 11	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 12	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 13	Contingency Reserve/Out of Economics	0	94
LINCOLN CT 14	Contingency Reserve/Out of Economics	0	92
LINCOLN CT 15	Contingency Reserve/Out of Economics	0	93
LINCOLN CT 16	Contingency Reserve/Out of Economics	0	92
MARSHALL 01	Reserve - Fuel Mgmt	0	380
MARSHALL 02	Reserve - Fuel Mgmt	0	380
MILL CREEK CT 03	Out of Economics	0	91
MILL CREEK CT 04	Out of Economics	0	91
MILL CREEK CT 05	Out of Economics	0	90
MILL CREEK CT 06	Out of Economics	0	87
MILL CREEK CT 07	Out of Economics	0	91
MILL CREEK CT 08	Out of Economics	0	91

Question #: NCWARN DEP DR4-5

Question Detail: In response to NC WARN's Data Request No. 3-1, the Company identified several units that were "not operating at full capacity" during several dates occurring in 2018-2019 and identified on Figure 9-A (page 74) of the Company's 2020 Integrated Resource Plan. Please identify the output in MW (if any) for the units identified in response to NC WARN's Data Request No. 3-1 at peak time for the dates on which responsive information was provided. (For clarity, the present data request is intended to ascertain the extent to which the units identified in response to NC WARN's Data Request No. 3-1 were operating below full capacity, or alternatively, were not operational.)

Response: DEP is providing the requested information for the dates in the time period 2018-2019. Because the explanatory parenthetical in the request provides more clarity on the intent of the request, data for each date are separated into those units/groups that were online and those that were offline. In addition, it appears the intent is to determine the additional MW capability which could have served additional load. The actual capabilities of the units/groups for these dates and times are not the same as the stated Net Dependable Capacities. Ambient conditions (e.g, temperature, humidity, sun angle and cloud cover for solar resources) have a significant effect, positive or negative, on the actual capability of a given unit. For this reason, the available unloaded capability for each unit is provided although it was not actually requested. For offline units, this value is estimated actual capability.

Some additional explanation is needed to fully understand the meanings of the reasons given.

- Online
  - Constrained – unit(s) temporarily constrained during some part of the hour, e.g., unit ramping up from a previous outage
  - Forced Derate – unit(s) constrained to operate at a lower level due to failure or limitation of one or more subsystems
  - Reliability – unit(s) constrained to operate at a specified level or range to avoid violation of reliability constraints
  - Reserves – the unloaded capacity is spinning reserve used for regulation and to provide a portion of contingency reserves
- Offline
  - Contingency Reserve – quick start unit(s) needed to complete contingency reserve needs
  - Forced Outage – unit(s) undergoing repairs due to an unforeseen/unplanned issue
  - Maint Outage – unit(s) undergoing planned maintenance or testing
  - Minimal Sun – integrated solar aggregate for the hour did not provide an entire MWh because sunlight was not strong enough to meet minimum inverter operation
  - Out of Economics – unit cost high enough and demand low enough to preclude need to run this unit
  - Reserve - Fuel Mgmt – unit(s) held in reserve to conserve a limited fuel
  - Reserve Shutdown – units in cold shutdown because longer term forecasts (weeks/months) indicated units would not be needed during the period

Data is provided for peaks for the following dates in 2018-2019: 01/02/18, 01/03/18, 01/05/18, 01/07/18, 01/08/18, and 01/16/18. As with the NCWARN DR3-1 response, the reason why each unit/group was not operational is indicated by the Reason column. Some units have been ungrouped from the NCWARN DR3-1 listing since loadings and available capacity differ for those in the group. Additionally, the tables have columns labeled Loading and Available to show the actual integrated hourly loading in MW and the unloaded MW capacity up to the actual capability of the unit/group for the given hour.

- Reasons marked with an asterisk (*) indicate that the unit(s) was/were online for a part of the hour but tripped before the end of the hour; for these units the Available column does not show the amount actually available but the amount that could have been available if not for the trip.
- NCEMC HAMLET 02 and 03 output is controlled by NCEMC and delivered to PJM.

DEP Units/Groups Not Operational at Full Capacity at 01/02/18 Peak

Online Units/Groups

Unit/Group	Reason	Loading	Available
ASHEVILLE 01	Reliability	185	2
ASHEVILLE 02	Reliability	184	1
ASHEVILLE CT 03	Forced Derate	124	1
BROAD RIVER IPP CT 01	Reliability	126	49
BROAD RIVER IPP CT 04	Forced Outage*	6	144
DARLINGTON CO. CT 13	Forced Outage*	63	70
NCEMC HAMLET CT 01	Reserves	55	1
NCEMC HAMLET CT 05	Reserves	55	1
SUTTON CT 04	Reserves	50	1
SUTTON CT 05	Reserves	50	1
WEATHERSPOON CT 01	Reserves	109	55

Offline Units/Groups

Unit/Group	Reason	Loading	Available
3RD PARTY SOLAR	Minimal Sun	0	0
BROAD RIVER IPP CT 02	Forced Outage	0	162
DARLINGTON CO. CT 01	Forced Outage	0	63
DARLINGTON CO. CT 03	Forced Outage	0	59
DARLINGTON CO. CT 07	Forced Outage	0	65
DARLINGTON CO. CT 12	Reserve - Fuel Mgmt	0	121
MARSHALL HYDRO	Forced Outage	0	0
NCEMC HAMLET CT 02	Out of Economics	0	56
NCEMC HAMLET CT 03	Out of Economics	0	56
WAYNE CT 12	Forced Outage	0	193

DEP Units/Groups Not Operational at Full Capacity at 01/03/18 Peak

Online Units/Groups

Unit/Group	Reason	Loading	Available
ASHEVILLE 01	Reliability	181	8
ASHEVILLE 02	Reliability	184	5
ASHEVILLE CT 03	Forced Derate	118	7
ASHEVILLE CT 04	Reliability	135	50
BROAD RIVER IPP CT 02	Reliability	143	29
DARLINGTON CO. CT 02	Reliability	52	12
DARLINGTON CO. CT 03	Reserves	57	6
DARLINGTON CO. CT 06	Reserves	54	8
DARLINGTON CO. CT 08	Forced Outage*	24	42
DARLINGTON CO. CT 10	Reliability	53	12
FAYETTEVILLE CC 01	Forced Derate	225	15
MAYO 01	Reserves	710	5
NCEMC ANSON CT 01	Reserves	54	2
NCEMC ANSON CT 02	Reserves	55	1
NCEMC ANSON CT 03	Reserves	26	30
NCEMC ANSON CT 04	Reserves	54	2
NCEMC ANSON CT 05	Reserves	54	2
NCEMC HAMLET CT 01	Reserves	55	1
NCEMC HAMLET CT 04	Reserves	54	2
NCEMC HAMLET CT 05	Reserves	55	1
RICHMOND CO. CC 04	Reserves	521	19
RICHMOND CO. CT 01	Reserves	162	27
RICHMOND CO. CT 02	Reserves	157	30
RICHMOND CO. CT 03	Reserves	163	22
RICHMOND CO. CT 04	Reliability	134	52
RICHMOND CO. CT 06	Reliability	135	52
ROXBORO 02	Forced Derate	639	4
SUTTON CC PB1	Reserves	703	14
WAYNE CT 10	Reserves	182	10
WAYNE CT 11	Reserves	182	10
WAYNE CT 12	Reserves	182	11
WAYNE CT 13	Reserves	176	15
WAYNE CT 14	Reserves	182	13

Offline Units/Groups

Unit/Group	Reason	Loading	Available
3RD PARTY SOLAR	Minimal Sun	0	0
BLEWETT CT	Forced Derate	0	51
DARLINGTON CO. CT 01	Forced Outage	0	63
DARLINGTON CO. CT 04	Forced Outage	0	66
DARLINGTON CO. CT 05	Forced Outage	0	66
DARLINGTON CO. CT 07	Forced Outage	0	65
DARLINGTON CO. CT 12	Forced Outage	0	133
DARLINGTON CO. CT 13	Forced Outage	0	133
DUKE SOLAR	Minimal Sun	0	0
MARSHALL HYDRO	Maint Outage	0	0
NCEMC ANSON CT 06	Forced Outage	0	56
NCEMC HAMLET CT 02	Out of Economics	0	56
NCEMC HAMLET CT 03	Out of Economics	0	56
WEATHERSPOON CT 01	Out of Economics	0	164

DEP Units/Groups Not Operational at Full Capacity at 01/05/18 Peak

Online Units/Groups

Unit/Group	Reason	Loading	Available
ASHEVILLE 01	Reliability	185	4
ASHEVILLE 02	Reliability	185	4
ASHEVILLE CT 03	Forced Derate	119	36
ASHEVILLE CT 04	Reliability	118	67
BLEWETT CT	Forced Derate	6	26
BROAD RIVER IPP CT 02	Reliability	144	28
BROAD RIVER IPP CT 03	Reliability	165	7
BROAD RIVER IPP CT 05	Reliability	161	11
DARLINGTON CO. CT 02	Reliability	53	11
DARLINGTON CO. CT 04	Reserves	54	12
DARLINGTON CO. CT 06	Forced Outage*	1	61
DARLINGTON CO. CT 07	Reserves	55	10
DARLINGTON CO. CT 08	Reliability	54	12
DARLINGTON CO. CT 10	Reliability	60	5
DARLINGTON CO. CT 12	Reliability	80	53
DARLINGTON CO. CT 13	Reliability	110	23
FAYETTEVILLE CC 01	Reliability	242	18
MAYO 01	Reserves	709	6
NCEMC ANSON CT 01	Reserves	54	2
NCEMC ANSON CT 02	Reserves	54	2
NCEMC ANSON CT 03	Reserves	27	29
NCEMC ANSON CT 04	Reserves	54	2

NCEMC ANSON CT 05	Reserves	54	2
NCEMC HAMLET CT 01	Reserves	54	2
NCEMC HAMLET CT 04	Reserves	55	1
NCEMC HAMLET CT 05	Reserves	55	1
RICHMOND CO. CT 01	Reserves	135	54
RICHMOND CO. CT 02	Reserves	162	25
RICHMOND CO. CT 03	Reserves	161	24
RICHMOND CO. CT 06	Reliability	139	48
ROXBORO 03	Reserves	692	6
ROXBORO 04	Reserves	707	4
SUTTON CC PB1	Reserves	632	85
SUTTON CT 04	Forced Derate	43	1
WAYNE CT 10	Reserves	162	13
WAYNE CT 11	Reserves	160	15
WAYNE CT 12	Reserves	174	1
WAYNE CT 13	Reserves	174	1
WEATHERSPOON CT 01	Reserves	20	144

Offline Units/Groups

Unit/Group	Reason	Loading	Available
MARSHALL HYDRO	Maint Outage	0	0
DARLINGTON CO. CT 01	Forced Outage	0	63
DARLINGTON CO. CT 05	Out of Economics	0	66
RICHMOND CO. CT 04	Forced Outage	0	186
NCEMC ANSON CT 06	Forced Outage	0	56
NCEMC HAMLET CT 02	Out of Economics	0	56
NCEMC HAMLET CT 03	Out of Economics	0	56
SUTTON CT 05	Maint Outage	0	50

DEP Units/Groups Not Operational at Full Capacity at 01/07/18 Peak

Online Units/Groups

Unit/Group	Reason	Loading	Available
ASHEVILLE CT 03	Forced Derate	153	2
BROAD RIVER IPP CT 01	Reliability	174	6
BROAD RIVER IPP CT 02	Reliability	171	1
BROAD RIVER IPP CT 03	Reliability	151	14
DARLINGTON CO. CT 04	Reserves	53	1
NCEMC ANSON CT 01	Reserves	55	1
NCEMC ANSON CT 02	Reserves	54	2

NCEMC ANSON CT 03	Forced Derate	27	1
NCEMC ANSON CT 04	Forced Derate	26	2
NCEMC ANSON CT 05	Reserves	55	1
NCEMC ANSON CT 06	Forced Derate	26	2
NCEMC HAMLET CT 01	Reserves	55	1
NCEMC HAMLET CT 04	Reserves	55	1
RICHMOND CO. CC 04	Reserves	498	52
RICHMOND CO. CT 02	Reserve - Fuel Mgmt	115	46
RICHMOND CO. CT 06	Reserve - Fuel Mgmt	107	66
SUTTON CT 05	Reserves	43	8
WAYNE CT 10	Reserves	136	46
WAYNE CT 11	Reserves	137	42
WAYNE CT 12	Reserves	141	36
WAYNE CT 13	Reserves	136	42
WAYNE CT 14	Reserves	154	28
WEATHERSPOON CT 01	Reserves	138	26

Offline Units/Groups

Unit/Group	Reason	Loading	Available
DARLINGTON CO. CT 01	Forced Outage	0	63
DARLINGTON CO. CT 05	Forced Outage	0	59
DARLINGTON CO. CT 08	Reliability	0	0
DARLINGTON CO. CT 10	Out of Economics	0	61
MARSHALL HYDRO	Maint Outage	0	0
NCEMC HAMLET CT 02	Out of Economics	0	56
NCEMC HAMLET CT 03	Out of Economics	0	56
RICHMOND CO. CT 04	Forced Outage	0	168
SUTTON CT 04	Out of Economics	0	51

DEP Units/Groups Not Operational at Full Capacity at 01/08/18 Peak

Online Units/Groups

Unit/Group	Reason	Loading	Available
BLEWETT CT	Maint Derate	4	64
DARLINGTON CO. CT 02	Reliability	52	2
DARLINGTON CO. CT 03	Reliability	52	1
DARLINGTON CO. CT 04	Reliability	53	1
DARLINGTON CO. CT 08	Reliability	53	7
DARLINGTON CO. CT 12	Reliability	100	20
DARLINGTON CO. CT 13	Reliability	100	10

NCEMC ANSON CT 01	Reserves	54	2
NCEMC ANSON CT 02	Reserves	54	2
NCEMC ANSON CT 03	Forced Outage	26	2
NCEMC ANSON CT 05	Reserves	16	40
NCEMC HAMLET CT 01	Reserves	55	1
NCEMC HAMLET CT 04	Reserves	55	1
NCEMC HAMLET CT 05	Reserves	55	1
RICHMOND CO. CT 01	Reserves	119	45
RICHMOND CO. CT 02	Reserves	116	45
RICHMOND CO. CT 03	Reserves	131	31
RICHMOND CO. CT 06	Reserves	105	68
SUTTON CC PB1	Forced Derate	570	13
SUTTON CT 04	Reserves	50	1
SUTTON CT 05	Reserves	50	1
WAYNE CT 10	Reserves	104	78
WAYNE CT 11	Reserves	102	77
WAYNE CT 12	Reserves	124	53
WAYNE CT 13	Reserves	157	21
WAYNE CT 14	Reserves	123	59

Offline Units/Groups

Unit/Group	Reason	Loading	Available
ASHEVILLE CT 03	Forced Outage	0	155
DARLINGTON CO. CT 01	Forced Outage	0	63
DARLINGTON CO. CT 05	Forced Outage	0	59
DARLINGTON CO. CT 06	Forced Outage	0	54
DARLINGTON CO. CT 10	Forced Outage	0	61
MARSHALL HYDRO	Maint Outage	0	0
NCEMC ANSON CT 04	Forced Outage	0	56
NCEMC ANSON CT 06	Forced Outage	0	28
NCEMC HAMLET CT 02	Out of Economics	0	56
NCEMC HAMLET CT 03	Out of Economics	0	56
RICHMOND CO. CT 04	Forced Outage	0	168

DEP Units/Groups Not Operational at Full Capacity at 01/16/18 Peak

Online Units/Groups

Unit/Group	Reason	Loading	Available
ASHEVILLE CT 03	Forced Derate	69	86
BROAD RIVER IPP CT 03	Reserves	171	1

DARLINGTON CO. CT 12	Reserves	108	25
HF LEE CC PB1	Reserves	1025	15
NCEMC ANSON CT 01	Reserves	54	1
NCEMC ANSON CT 02	Reserves	53	2
NCEMC HAMLET CT 01	Reserves	55	1
NCEMC HAMLET CT 04	Reserves	55	1
NCEMC HAMLET CT 05	Reserves	55	1
RICHMOND CO. CC 04	Reserves	532	8
RICHMOND CO. CT 01	Reserves	140	23
RICHMOND CO. CT 02	Reserves	138	21
RICHMOND CO. CT 03	Reserves	151	15
RICHMOND CO. CT 04	Forced Derate	97	38
RICHMOND CO. CT 06	Reserves	140	20
SUTTON CT 04	Reserves	50	1
SUTTON CT 05	Reserves	50	1
WAYNE CT 11	Reserves	112	70
WAYNE CT 12	Reserves	153	29
WAYNE CT 14	Reserves	160	24

Offline Units/Groups

Unit/Group	Reason	Loading	Available
BLEWETT CT	Forced Derate	0	34
BROAD RIVER IPP CT 01	Out of Economics	0	171
BROAD RIVER IPP CT 02	Out of Economics	0	165
BROAD RIVER IPP CT 04	Out of Economics	0	178
BROAD RIVER IPP CT 05	Out of Economics	0	174
DARLINGTON CO. CT 01	Forced Outage	0	63
DARLINGTON CO. CT 02	Out of Economics	0	60
DARLINGTON CO. CT 03	Out of Economics	0	59
DARLINGTON CO. CT 04	Out of Economics	0	66
DARLINGTON CO. CT 05	Forced Outage	0	66
DARLINGTON CO. CT 06	Out of Economics	0	62
DARLINGTON CO. CT 07	Out of Economics	0	65
DARLINGTON CO. CT 08	Out of Economics	0	66
DARLINGTON CO. CT 10	Forced Outage	0	65
FAYETTEVILLE CC 01	Forced Derate	0	225
HARRIS NUCLEAR 01	Forced Outage	0	0
MARSHALL HYDRO	Maint Outage	2	0
NCEMC ANSON CT 03	Out of Economics	0	56
NCEMC ANSON CT 05	Out of Economics	0	54
NCEMC ANSON CT 06	Out of Economics	0	56

NCEMC HAMLET CT 02	Out of Economics	0	56
NCEMC HAMLET CT 03	Out of Economics	0	56
WAYNE CT 10	Out of Economics	0	182
WAYNE CT 13	Out of Economics	0	177
WEATHERSPOON CT 01	Out of Economics	0	164

Attachment 4

Transcript of NCUC Staff Conference, March 2, 2015

STAFF CONFERENCE MONDAY, MARCH 2, 2015

CHAIRMAN FINLEY: Let's come to order, please. In compliance with the State Ethics Act, I'll remind the members of the Commission of their duty to avoid conflicts of interest, and inquire whether any member of the Commission has a known conflict of interest with regard to the matters coming before the Commission this morning?

(No response.)

CHAIRMAN FINLEY: If there are no conflicts, then we will proceed with Public Staff, Electric.

MR. SAILLOR: I'm Scott Saillor with the Electric Division. Item P1 consists of registration statements and applications for certificates of public convenience and necessity for four solar facilities.

The Public Staff recommends that the Commission approve the applications, issue the certificates and accept the registration statements.

COMMISSIONER BEATTY: Move approval of the recommendation.

COMMISSIONER RABON: Second.

CHAIRMAN FINLEY: It's been moved and seconded that we approve this item. Are there questions? Is there discussion?

(No response.)

Motion is approved and adopted.

(MOTION MADE AND PASSED TO ADOPT THE RECOMMENDATION.)

CHAIRMAN FINLEY: All right. The next item on our agenda is to hear from Duke Energy Carolinas and Duke Energy Progress with respect to adequacy during the recent cold weather events.

MR. PEELER: Good morning. My name is Nelson Peeler, and I'm the Vice President of Transmission System Operations for Duke Energy. And this morning I'd like to just talk to you a little bit about the recent extreme cold weather that we experienced in the Carolinas and the performance of our systems here for Duke Energy Progress and Duke Energy Carolinas.

Each of you should have a handout, and I'll walk through this fairly quickly, but starting on page 2, just to kind of level set, is just a representative typical winter, late January, early February for the Carolinas. And, really, the point here is just to show that typical weather for us that time of year is mid-to-upper 20s and 30s across the state for typical lows.

Moving on to the next slide, I'll speak just a bit about preparations that the Company takes for extreme cold weather situations. And we use, you know, continuous learning exercises. We did a pretty elaborate lessons-learned exercise after the January of 2014 polar vortex where we saw some very extreme temperatures, and we've implemented a lot of lessons into our planning process.

And for this particular cold weather, we began to see roughly seven to 10 days ahead that we were going to experience some very cold weather -- it was unseasonably cold for this time of year -- and began our detailed preparations roughly a week ahead of time. Those detailed preparations included preparing our generation fleet through any kind of maintenance activities that need to be done prior to that day, and planning to defer or delay any type of activities, you know, close to that event and during that event that could potentially jeopardize any of our generation fleet or our transmission or distribution systems. So that included significant transmission studies to determine if we had outages that needed to be restored back to the system due to maintenance activities, things like gas pressure, checking on various breakers to prepare for cold weather, checking freeze protection on generation units, just a long checklist, if you will, of preparation in that week prior to.

Some specific things, we have some seasonal things we do. We do participate in a number of industry activities. NERC and the North American Transmission Forum have done extensive cold weather lessons learned over the past two years. We've been an active participant in those and have implemented a lot of their recommendations. We also have begun holding a cold weather seminar. Actually, we do a hot weather seminar, too. But in October we do an enterprise wide, across the company, webinar with our various departments in the company, generation, transmission, distribution, communication, fuels, as a preparation for moving into the winter season. That was held in October this year.

As we moved into this day, we also work with our neighbors through our VACAR reserve sharing. We shifted our reserve sharing calls to 6:00 a.m. in the morning for that week so that we could be prepared, versus their normal time is later in the day. And we usually do that shift in the wintertime to deal with winter peaks. And we began holding tailgate meetings and communicating with our various wholesale customers. So a lot of preparation to be prepared.

So I'll move on to the next slide which shows the temperatures across the state the afternoon prior to the peak on February 20th. So this is roughly 4:00 p.m. on the 19th, which represents pretty close to the high temperature for that day. And the main thing to note here is that these high temperatures are generally lower than the typical low temperatures, so we were in a very cold weather pattern.

And moving to the next slide, it shows our low temperatures the next morning, which are, you know, single digits across a good bit of the state, particularly in largely populated areas like Charlotte and Raleigh. So this was a very cold, broke a number of temperature records for this time of year across the state, so we did experience not the coldest temperatures ever in the state, but some very cold temperatures for mid-February.

So the next slide is a representation of our capacity situation for this event. And there are three columns here. I'll just give kind of a quick overview of what each of these columns represent. The first column labeled IRP is really the IRP numbers, as what many of you are used to seeing, and represent our capacity and our obligation, and then a calculated margin associated with that. The middle column is what we call Operating Plan, which is what we would prepare going into a season, so these would be the numbers we would prepare for as we moved into winter season. So as we're getting closer to wintertime, say, in the fall, we would be preparing based on weather forecasts, based on generation availability, based on any new things we know versus the IRP which is more of a normalized long-range plan. This would be our seasonal plan. So as we move into winter, these were -- this was what we were planning for. So we were planning for, you know, an obligation here before DSM of 19,473. And you'll see the third column is actually what we experienced on the 20th, so you'll see that we experienced considerably higher loads, obviously because of the considerably lower temperatures. As we were doing our planning, we were not planning for -- expecting, rather, single-digit temperatures in the middle of February. So that reduced our margins considerably as we went across that peak on February 20th.

I'll pause here, and if there are questions, take questions, or I'll move on to the other slides. Yes, sir.

COMMISSIONER BEATTY: A couple questions. Going back to slide number 3, what's does a tailgate team mean?

MR. PEELER: Yes. Sorry. The tailgate team essentially is our internal preparations. So we would get together with our system operations, transmission, distribution, generation, regulatory affairs, fuels and optimization teams, all the internal folks who contribute to meeting this peak demand, and talk about preparations.

So an example would be a week ahead we saw a much colder day coming, which produces a larger load than we typically expect that time of year, so we've got to be prepared to meet it. So we all get together and say, okay, here's the weather we see coming, here's the forecast of load that we see coming, now let's talk about how we're going to meet it. So we go through very detailed, which generation units are going to be available, what type of fuel burns are we going to use on each plant, whether we're going to be burning oil or gas or -- the very details of the hour-by-hour operational plan being prepared. So it's just a preparation team.

COMMISSIONER BEATTY: I just sort of envision people standing at the back of a car.

MR. PEELER: So we actually do it in a room inside, not outside in the parking lot.

COMMISSIONER BEATTY: And then on that same page, what do you mean by "Communicating with wholesale customers to ensure complete preparedness for the BAAs"?

MR. PEELER: Yeah. So --

COMMISSIONER BEATTY: What do you mean, "complete preparedness," and what are BAAs?

MR. PEELER: So BAA is a Balancing Authority Area, so that's essentially our control area. And the preparation there is to ensure that they're prepared so that we understand what their loads or any contributions from their -- from the DSM or others is going to be, so it's really a communication plan to understand. So, again, we're essentially -- I would say we're extending our tailgate message a bit out to our wholesale customers as well, okay?

COMMISSIONER BEATTY: Thank you.

MR. PEELER: Yes, sir.

COMMISSIONER BAILEY: Was there any available neighbor power on that date, on February the 20th? Could you have gotten some power from the -- or to the south or to the north of us?

MR. PEELER: Yeah. So you're talking about purchased energy?

COMMISSIONER BAILEY: Yes.

MR. PEELER: Yeah. So we actually did purchase some energy on the 20th, and we did purchase a little bit of capacity as well. So we checked all around. So, you know, Santee, South Carolina Electric & Gas, Southern Company, DBA, PJM and so forth. So there was some non-firm energy available which we ended up purchasing across the peak, and little bit of capacity. I think we purchased a little bit of capacity from South Carolina Electric & Gas across the peak and a little bit from Southern Company.

CHAIRMAN FINLEY: Was that energy capacity pricy? Was it expensive in this particular condition?

MR. PEELER: It was. I don't have the prices off the top of my head, but certainly. This was a peak demand. So PJM broke their all-time peak demand. It was cold down in Atlanta and Birmingham and all around. So it's a high-cost time for energy. Gas prices were also pretty high as well.

Okay. I'll move to the -- the next slide, really, is just a pictorial. I won't spend a lot of time on it, but really, it's just a -- it's a good representation to show the importance of the diversified fuel mix we had to meet this peak. This represents the capacity mix for that integrated hour ending at 8:00 for DEC. It's a nice mix of nuclear, coal, gas, and then hydro as well, with a little bit of purchased power with it. Okay?

CHAIRMAN FINLEY: In meeting this demand with combined cycle and combustion turbines, any problems getting gas to the units?

MR. PEELER: I'm not aware of any specific problems. We did do some -- or in the preparation up to this we did, you know, use a little bit of oil to make sure we had adequate gas across the peak. It was really more of ensuring we had it across the peak, but there was no supply issue.

CHAIRMAN FINLEY: Okay.

MR. PEELER: Yes, ma'am.

COMMISSIONER BROWN-BLAND: This pictorial is the actual capacity mix for that particular day. How does it compare, if you know, to the capacity mix from the IRP?

MR. PEELER: Oh, I don't know. This is for the particular hour, so this is just one hour of mix, just to represent that kind of real time. I don't have that. I'm sorry. I just don't have that off the top of my head.

COMMISSIONER BROWN-BLAND: Okay. Thank you.

MR. PEELER: Okay. So I'll move on to the next slide which is a similar representation for Duke Energy Progress. It has the same three columns on it: IRP, Operating Plan, and then the real-time hour for the February 20th hour ending 8:00. And you'll see in this case that, again, the supply resources -- or I'm sorry -- the obligation was significantly larger, and both of these operating companies met their all-time or exceeded their all-time peak demand in this day, so these are very large numbers for this time of year. And you'll note here as well, DEP also was receiving non-firm energy across the peak to serve the load.

And one thing I will note is that 500 MW of this non-firm for DEP was coming across our joint dispatch agreement from DEC during this hour. Of that 700, 500 of that was across the joint dispatch agreement.

CHAIRMAN FINLEY: Mr. Peeler, down at the bottom of the page there you've got Capacity Margin -1.6%, Reserve Margin -1.6%. What does that mean?

MR. PEELER: Yeah. So the actual capacity across this peak, as calculated, there was negative capacity and the load was met with non-firm energy. So that 700 MW of non-firm energy was used to serve the load and there was not reserve capacity for this hour.

CHAIRMAN FINLEY: So how far were you away from having to shed load?

MR. PEELER: Well, so certainly there were several other options still available. We had not called on VACAR reserves, so we still had firm transmission availability to bring reserves in. There were still energy options. We still could have pushed more non-firm energy. But, you know, several things could have happened that could have pushed us there pretty quickly, so loss of a couple of large units, something unknown like that certainly could have pushed us close to that. We were certainly prepared to utilize that, if necessary, but we were not -- it wasn't imminent by any means.

CHAIRMAN FINLEY: So if you had been in a situation where you had to shed load, sort of outline for us what you would have done.

MR. PEELER: Yeah. So dependent on the amount of -- you know, certainly the amount of time -- let's just play a fairly real-time scenario. If we had lost a large unit across the peak and had a short time, you know, like a less than 15-minute response time to shed load, so we already had tested and prepared our load shedding tools. We have a tool that allows us to do rotating load shed. So we would have begun communication and activation of that load shed program within a few minutes, based on the amount that was needed. So just a couple hundred MW would probably -- would be a likely number, then we would have been rotating that amount until we were able to recover that.

CHAIRMAN FINLEY: So in the rotation, who gets cut off first?

MR. PEELER: Yeah. So our distribution circuits are classified by category, so hospitals and emergency and those types of things are not in the list. It's predominantly residential customers because of the health and safety aspect of, you know, not impacting emergency services and those types of things. So it's going to be predominantly residential circuits. And the automated tool basically identifies the amounts we need in the areas that it can be done. So there's no -- we're not picking names by any stretch of the imagination. It's simply a tool that selects the amount of load needed in the areas of those Class 3 circuits which are, again, predominantly residential, which means they don't have hospitals and medical services and airports and those types of things on them. So I guess the short answer is it's a relatively random, if you will, selection out of that group of database.

CHAIRMAN FINLEY: Does this mean that Duke and

Progress are now winter peaking companies?

MR. PEELER: It does for now. We actually became winter peaking last January. Both footprints peaked with the polar vortex in January, so this is -- we're currently both winter peaking.

COMMISSIONER BAILEY: And so with that said, that pretty much means any solar installation you've got, utility out there, 1,000, 2,000 MW is not going to be a lot of good at 7:00 or 8:00 a.m. on a winter morning; is that correct?

MR. PEELER: That's correct. So the instantaneous peak would typically be, this time of year, 7:20, something like that, sunrise, pretty close to that time. But the solar essentially doesn't wake up and produce that quickly. So for this integrated hour, we had a couple of percent contribution probably of the nameplate of solar. Probably five or so percent is what we have measured, so very little contribution to a winter peak. Okay.

So I'll move to the next line which, again, is a -- this is the same kind of picture that we saw for DEC. This is just simply showing the capacity mix for this hour. And you'll see, you know, a similar diverse mix of how this demand was met. Okay.

So I'll move to my last slide, which is number 10, which is really just a summary here, a couple points that, you know, even with a lot of good planning, a lot of good performance from the system, you know, it still required us to bring in non-firm energy to meet this demand because it was a very extreme load day for this time of year. We did a lot of preparation ahead of time. Like I said, we prepare seasonally with significant planning. We also began a lot of activities in the week ahead as soon as we could see the forecast, so very important. You know, our meteorological staff gives us a look ahead and says, hey, you know, I'm seeing something 10 days out, let's talk about it.

So we began with, you know, restoring transmission system, doing a lot of -- completing maintenance activities and deferring maintenance activities across this peak. We stopped vegetation management activities because of the potential risk of, you know, causing an outage. And we stopped a lot of IT work and did some preparation work on our IT systems to make sure they were sound across this peak. We, you know, evaluated ratings. We evaluated relay settings, just a lot of activity to be prepared for this, really, a very different level of load than typical.

Certainly, an important message here is that, you know, we used a good bit of -- we really utilized essentially all of the demand-side management type programs we had. They were very effective. Customers were very responsive to those programs. Additionally, we asked for voluntary conservation. You know, while it's certainly hard to measure that exactly, we're very convinced that that was helpful across this peak, even though we can't measure it explicitly.

And a last comment here, really, is our wire systems. The transmission and the distribution system both, they stood up very well to this, even in very extreme temperatures and load, really very little issues associated with those. It allowed, once we were able to generate this energy, to deliver it in a very effective manner.

CHAIRMAN FINLEY: Mr. Peeler, there's a lot of talk these days about deficiencies and regional and inter-regional planning. You've got FERC Order 1000. Did this event, these events, these cold weather events point out to you whether or not your regional and inter-regional planning is deficient or needs to be improved in some fashion?

MR. PEELER: There were no deficiencies that I could identify. The transmission system from the bulk system on down into the lower voltage levels performed very well. We were able to bring in -- you know, I think we were importing about 1,200 MW of energy at one time into our BAA. That's a sizable energy move in a very stressful time. So we were able to move energy in from PJM. We moved energy in from Southern Company. We had our reserve sharing capabilities on our firm transmission. So I didn't see any deficiencies. As a matter of fact, I was pleasantly surprised at the performance of not just the Duke Energy transmission system, but our neighboring systems as well. We were in very close contact with them throughout the event; really good performance.

CHAIRMAN FINLEY: What, if anything, does this say about the Company's vegetation management policies? I mean, we get complaints and you get complaints from time to time about the Company being overly aggressive in cutting trees and limbs and that type of thing. Well, that's usually not in these cold weather events. Could you comment on that?

MR. PEELER: Yeah. So I'm sure that, you know, that would come up a lot more from the ice and snow events versus the extreme cold, but the general comment is I think that we have a very solid program. We try to balance the reliability needs and the customer issues as well, but we certainly don't need to be less aggressive in trimming to maintain effective clearances. And in this event we had no issues from vegetation, that I'm aware of, from the cold.

CHAIRMAN FINLEY: But that's not necessarily included in these discussions the last few days where we've had the ice and snow in the Triad and the Triangle?

MR. PEELER: Yes. Yeah, I mean, there certainly were tree issues from the heavy snow and trees weighting down with snow falling on our lines, certainly, but, again, I think that's the -- I think that our vegetation program made that a less impact, but I think it also tells us we can't stand down from that. That's my point. Am I answering your question?

CHAIRMAN FINLEY: Yes, sir.

MR. PEELER: Yes, ma'am.

COMMISSIONER BROWN-BLAND: I assume that the Company was able to make contact with its larger customers, and I think you sort of referenced that earlier and said that you were in contact and had some idea of what they were doing and did or didn't do to conserve, but I also think -- during this time period I recall that there were announcements made by radio and other media asking -- I assume targeted at residential customers to conserve. And I understand that you said, you know, you don't really have a really good way to measure that at this point, but what do you base -- or what information, if any, do you have to realize that your message, one, reached the intended target and, two, that there was some response and, you know, any lessons learned about needing to make any changes in that in the future?

MR. PEELER: Sure. So from a program -- from a large customer base, our account managers, they're provided information out of our planning sessions, and so they can contact their customers that they support, particularly those that are in our demand-side management program. So we can measure their performance in that, and they all responded very well. From a voluntary basis, we were asking customers, you know, to voluntarily conserve. The difficulty in measuring that is we have no -- we don't have a measure on each of their individual, you know, meters and so forth.

However, one way we can look at, we do get feedback, particularly on social media, so we know people heard the message, right, and some positive social media and some not. But we definitely know the message got out. From an estimating impact, we have a low -- you know, we have a forecasting tool that says we think the low is going to be this. And based on, you know, how it actually comes in and a comparison to what we projected, we can see some amount of difference that we believe is voluntary conservation. So that's the best I can -- that's really the best we have. It's a model of load with no voluntary conservation, and then what we see is as a difference, so we see a little bit there.

COMMISSIONER RABON: On your social media, I will say I followed Duke on Twitter just to see, and I thought it was very effective, the tips you also put on there to help people. And like you said, there are a few that complain, but overall I think that's a very good tool and program you all are running.

MR. PEELER: Right. Thank you.

CHAIRMAN FINLEY: Other questions for Mr. Peeler?

COMMISSIONER DOCKHAM: Just one. Thank you, Mr. Chairman. Last year we were all talking about the polar vortex, and I'm just curious how this latest event compared to that and what you learned from both events, and is it over? I hope it is.

MR. PEELER: So the comparison between the two, the polar vortex last year was in early January, so that is a time we would expect colder temperatures. So the deviation from norm was probably not quite as big as this was. Also, on the polar vortex, we didn't get multiple, really cold days ahead of the event, so if I remember, it was 60 degrees a day or two before the polar vortex before it dipped down into the single digits.

The difference this time was it was much later in the year, so mid-February, almost late February, and we got 36 or 40 hours of really cold weather ahead of it. So that tends to have a bigger impact on the ultimate load, when it's colder for longer. It's also more stressful on the systems. So the generating units are running, you know, harder longer. All the various mechanical components of our systems are under more stress. So the difference that we saw was it was a shift in, you know, by more than a month in the time of the year, so a little more surprising that it was so cold and then the fact that it was cold for so long. As far as predicting the future, I really can't help you.

CHAIRMAN FINLEY: All right. Thank you.

MR. PEELER: Thank you.

MR. SMITH: Good morning. My name is John

Smith. I'm responsible for the construction and maintenance of the Carolinas Delivery Operations Group for both Duke Energy Carolinas and Duke Energy Progress. And I share that responsibility with a peer that is in Charlotte. I'm here in Raleigh. I appreciate your time today.

We handed out a summary of the events that we've been through, and Mr. Peeler described what occurred back on Friday and Saturday two weeks ago or a week and a half ago. And on the front of that and on the back of that there were some significant storms, and these are the stats, okay? Just in summary there, there was about a million customers, between the wind storms that started on Valentine's Day night and then through the snowstorm that we just got through last Friday, there was about a million customers that had lost power. Overall, those customers, for those three events, they were put back in service within a 48-hour period for each event. All right.

The latest event, there was 475,000 customers impacted last Thursday with the snow and the freezing rain that came through primarily the Triangle area, all right, and 85 percent of those customers were back on by Thursday night, with the remaining customers in the hardest hit areas, which were Durham and Zebulon, coming back by late Friday night, and there were a few -- a handful that ran into Saturday morning.

I'd like to highlight just when we look at -- we talked about vegetation management. Over the last few years we've been doing a lot of things with our system, distribution system, specifically, and the system held up very well through these three events. The vegetation management, the tree trimming that we've done in the areas on those circuits that we've talked about over the last few years, produced great benefits during this storm because those areas there were not as impacted as some of the areas where we're still implementing the program. So that was one, plus the enhancements we made to our system, specifically with all the reclosers that we've been able to put in and allow us to be able to segment down to just the areas that were impacted, that also helped.

Secondly, the scale of Duke Energy, when you think back to the merger and combining the two companies in the Carolinas, that is really where we get to see the scale. And considering the storms that we had last year, remember Valentine's Day and then March 5th we had the two major ice storms, we've really been able to capitalize on the resources we have. On these storms here, we didn't know where they were going to hit. Just like you, we were looking at the map and saying, okay, where's that ice going to hit, where's the 32-degree freezing line, and we were able to quickly deploy resources from those areas that were not impacted into the areas that were impacted to do two things: one is assess, tell us what the damage is and how many resources we needed, and then secondly, start putting the lights back on right away. And we were able to do that very successfully, some within an hour or two from the time when we actually knew where the storm was and that we can get there safely. So that was the second part. And by the way, through this entire event of two weeks here, we did not have one personal injury and/or one significant public safety event during that time.

So, lastly, I'll talk about our communications. And we talked about social media. You know how important that is in being able to keep contact with our customers, and that's something we strive for every single day in improving. During these events, we focused extremely hard on being able to, one, identify what our issues were, where they were located, and then getting that information out quickly, transparent information to the customers. We worked with local officials, we worked with the emergency management agencies, our large customers, residential, and the media markets to be able to provide the information so that they can prepare properly for when power was going to be restored.

Now, we still have some opportunities in there and we've got some customers that share that with us and we're working on those, but overall, those three areas, I think, were benefits that we saw out of being the big Duke Energy across the Carolinas, where we're able to use that magnitude and continue to capitalize on the investments we're making in the system.

With that, I'll ask if there's any questions. I do appreciate your time. I just thought it was very timely that we can talk, coming off the heels of the snowstorm from last week.

CHAIRMAN FINLEY: You redispatched crews within the Duke Progress system to the areas of greatest need. Did you have to call upon crews from other companies in other states?

MR. SMITH: Yes, Mr. Chairman. We actually -- for the ice storm, we deployed some of our Florida resources up to the Columbia area. And once again, we were chasing an ice storm, not knowing where it was going to hit, but we knew we would be impacted from the west to the east. And we actually had those resources right staged so that we could dispatch them, whether it be coming across 85 up into the I-95 corridor, those areas, and/or send them out west. And that was the only external resources we actually brought in, other than a few internal resources within North Carolina and from our -- and they were contract resources from the co-ops for contractors that work for us.

CHAIRMAN FINLEY: And I gather a lot of the outages in this last week were from this wet snow that broke limbs and caused trees to fall over; is that right?

MR. SMITH: Primarily a tree and limbs on wire and/or wire down caused by the heavy snow, some icing on our wires, but the majority was from trees falling into our lines. I happened to stop by one of our big op centers in Garner on the way in this morning and got to thank the employees for their efforts over the last two weeks. And I asked them specifically about the circuits that had been trimmed, and they were not the ones that gave us problems this time. It's the ones we're trimming, okay? So, yeah, certainly that type of snow, and the ice storm brought trees down on our lines.

CHAIRMAN FINLEY: You know, there are a lot of trees and limbs inside Raleigh here. It seemed like there were outages, and I heard from my neighbors about all that, so I guess you still have that problem of cutting too much or too little within the urban areas.

MR. SMITH: Cutting -- for us, the problem is not cutting enough, but for most of the neighbors, the concern actually is cutting too much and getting those right of ways cleared and how we leave -- and the appearance afterwards, okay, so that's a challenge I think we'll continue to face as we trim. But we don't face those challenges on days like last Thursday, all right? Most people aren't asking about the trees. They're asking when the wires can go back up and when the lights can come back on.

CHAIRMAN FINLEY: They'll forget about that in July. Other questions?

COMMISSIONER BROWN-BLAND: Not a question. I would just like to say thank you, Mr. Peeler and the Company, for realizing the importance of coming and sharing this information with us and keeping us educated. We have a lot to learn, and always glad to hear information like this, and so we appreciate that and I thank you for it.

MR. SMITH: Well, thank you for your support.

CHAIRMAN FINLEY: All right. Thank you, Mr. Smith. We appreciate you and Mr. Peeler coming and informing us today. It's been educational. Anything else?

(No response.)

CHAIRMAN FINLEY: Let's approve the minutes of February 23.

COMMISSIONER RABON: Move approval.

COMMISSIONER DOCKHAM: Second.

Motion is approved and adopted.

(MOTION MADE AND PASSED TO ADOPT THE RECOMMENDATION.)

CHAIRMAN FINLEY: And while we're at it, let's approve our upstairs minutes of February 9th.

COMMISSIONER BEATTY: Move approval.

COMMISSIONER RABON: Second.

Motion is approved and adopted.

(MOTION MADE AND PASSED TO ADOPT THE RECOMMENDATION.)

CHAIRMAN FINLEY: If there's nothing further, we shall be adjourned.

(Whereupon, Staff Conference was adjourned.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing proceeding was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said proceeding.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 14th day of March, 2015.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150