

ATTACHMENT 1
[Initial Comments of NC WARN and CBD]
Docket No. E-100, Sub 165

**Review of Duke Energy Carolinas, LLC and Duke
Energy Progress, LLC's 2020 Integrated Resource
Plans**

NCUC Docket No. E-100, Sub 165

By: William Powers, P.E.

March 1, 2021

Attachment 1
NC WARN & CBD's Initial Comments

I. Executive Summary

Duke Energy Carolinas, LLC (“DEC”) and Duke Energy Progress, LLC (“DEP”) (collectively “Duke Energy” or “Companies”) advance a preferred strategy in the 2020 Integrated Resource Plans (“IRP”) centered around expanding gas-fired capacity as the primary mechanism to phase-down coal-fired generation and reduce greenhouse gas emissions. The strategy assumes that a solar and battery storage alternative to combustion turbines would be three to four times more expensive, that only a limited amount of solar power could be utilized – even with battery storage – before it would have to be curtailed, and that Duke Energy must build and maintain high levels of gas-fired capacity to meet winter peak loads. Duke Energy also assumes that relatively little customer-owned solar and battery power will be developed over the 2021-2035 planning horizon of the IRPs.

This report addresses flaws in Duke Energy’s: 1) reporting of winter peak reserve margins, resulting in excessive capacity, 2) cost assumptions, and 3) calculation of potential solar and battery contributions to the portfolios included in the IRPs. A “Modified Earliest Practicable Coal Retirements” portfolio is presented as a portfolio alternative that eliminates coal-fired capacity as early as 2022, displaces the proposed combustion turbine capacity with battery capacity, and includes a high proportion of customer-owned solar and battery capacity to maximize resiliency and minimize the cost of the portfolio to Duke Energy customers.

II. Corporate, National and State Climate Commitments

A. The Flaws in Pricing of Battery Storage and Gas-Fired Generation in Duke Energy’s Purported Commitment to Carbon Neutral Electricity Generation by 2050

Duke Energy established the goal of net-zero CO₂ emissions from electric generation by 2050 as described in its 2020 Climate Report titled “Achieving a Net Zero Carbon Future.”¹ Duke Energy’s 2020 Climate Report, and its net-zero goals, received extensive discussion as part of the IRPs of DEC² and DEP.³ According to Duke Energy, its electric utilities systemwide will achieve this goal in the following manner:⁴

¹ 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.

² DEC’s 2020 IRP, pp. 131-42.

³ DEP’s 2020 IRP, pp. 132-42.

⁴ Duke Energy 2020 Climate Report, p. 1.

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 2020 Climate Report envisions that over time the natural gas fleet will transition from providing baseload power to a peaking role.⁵ In fact, 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."⁶ Duke Energy summarizes the role of natural gas in 2050 in the following manner:⁷

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.

Duke Energy does acknowledge that battery storage will play a role, but expresses skepticism that currently available battery technology will be capable of serving as baseload and intermediate power supply. A concern of the Companies 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 Duke Energy says it would need to avoid adding new gas capacity.⁸

Duke Energy's claim that the electric utility industry has little meaningful experience with batteries is unsupported.⁹ In fact, battery storage capacity is rapidly expanding in the U.S., especially at utility scale, as shown in Figure 1 (gray bar). Battery storage deployments are expected to reach 7,500 MW per year in 2025. There will be no supply issues with Duke Energy achieving a cumulative battery storage installation target of 15,000 MW by 2030.

⁵ 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."

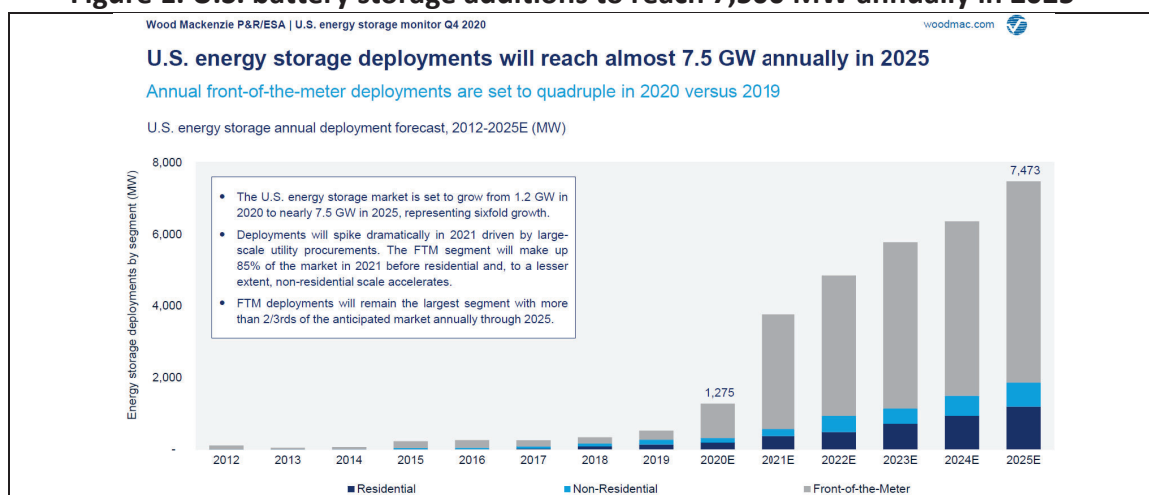
⁶ Ibid, p. 16.

⁷ Ibid, p. 28.

⁸ Ibid, p. 2.

⁹ 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."

Figure 1. U.S. battery storage additions to reach 7,500 MW annually in 2025¹⁰



Assuming the 15,000 MW battery storage target is feasible, Duke Energy asserts that the incremental costs of achieving net zero with battery storage would be three to four times the cost of the net-zero scenario using natural gas. Duke Energy expresses concern for the impact these battery storage costs could have on its low- and fixed-income customers.¹¹

The cost delta Duke Energy claims between battery storage and gas-fired generation is eliminated when accurate capital costs are assumed. Duke Energy assumes a lithium battery cost of approximately \$900 per kW for battery storage with 4 hours of storage capacity, equal to \$225 per kilowatt-hour (kWh), and cites to National Renewable Energy Laboratory (“NREL”) as the source of this cost information.¹² This appears to be the mid-range capital cost that NREL forecasts for battery storage in the 2027-2028 timeframe.¹³ The NREL battery storage cost estimate is not unreasonable for 2020, but high for 2027-2028, the mid-range years of the 15-year planning horizon of the 2020 IRPs.

A survey of leading battery manufacturers indicates that battery capital costs are already lower than the NREL forecast for 2027-2028 and steadily declining, as shown in

¹⁰ 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>.

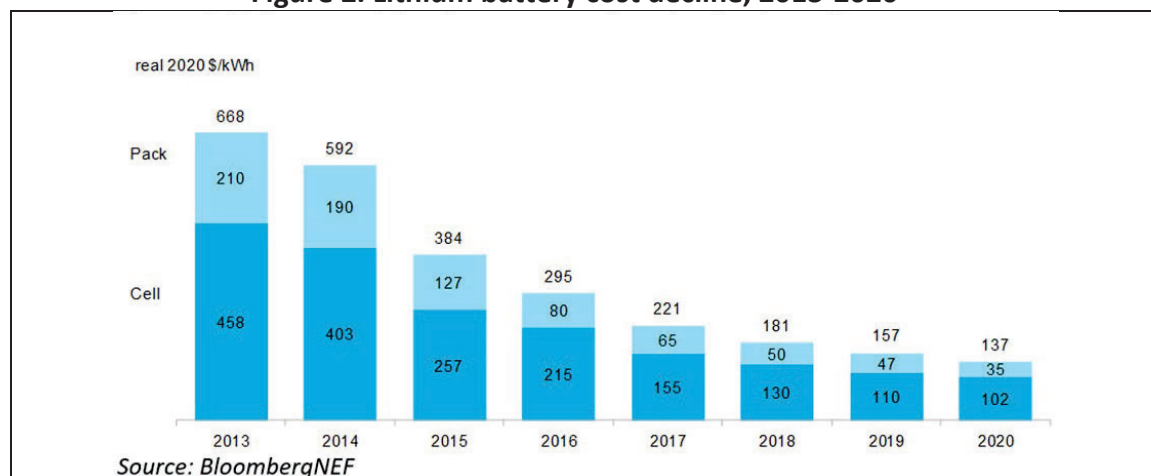
¹¹ Duke Energy 2020 Climate Report, p. 3.

¹² Ibid, p. 24, footnote 19. NREL, Electricity Annual Technology Baseline (ATB) Data Download – 2020 ATB Data, “Storage” tab, webpage accessed February 19, 2021: <https://atb.nrel.gov/electricity/2020/data.php>. The “moderate” battery storage capital cost is approximately \$900/kW for 4-hour duration in the 2027-2028 timeframe.

¹³ Wood Mackenzie Power & Renewables and U.S. Energy Storage Association, *U.S. Energy Storage Monitor Q4 2020 Executive Summary*, December 2020, p. 8. The said Wood Mackenzie report is attached as **Attachment 2**.

Figure 2, and are expected to reach approximately \$100/kWh by 2023.¹⁴ This is about one-half the lithium battery price assumption assumed by Duke Energy for 2027-2028. Use of an industry forecast 2023 battery capital cost, the capital cost for the third year in the 2021-2035 IRP planning period, is a conservative approach if only one capital cost value is used to model battery costs for the entire 15-year planning period.

Figure 2. Lithium battery cost decline, 2013-2020¹⁵



Note: A battery pack and battery cells are the two elements of a functional lithium battery.

Conversely, Duke Energy's capital cost assumptions for gas turbine power plants, \$650/kW for combined cycle and \$550/kW for combustion turbines, are less than one-half what they should be to reflect Duke Energy's actual costs.¹⁶ The capital cost of the 560 MW Asheville combined cycle plant, which came online in 2020, is \$817 million.¹⁷ This is equivalent to a unit cost of about \$1,460/kW,¹⁸ over double Duke Energy's assumed combined cycle cost of \$650/kW. The same NREL database that Duke Energy referenced as the basis for its battery storage cost in its *2020 Climate Report* identifies a generic mid-range capital cost for combined cycle plants of \$1,055/kW in 2021,

¹⁴ BloombergNEF, *Battery Pack Prices Cited Below \$100/kWh for the First Time in 2020, While Market Average Sits at \$137/kWh*, December 16, 2020: <https://about.bnef.com/blog/battery-pack-prices-cited-below-100-kwh-for-the-first-time-in-2020-while-market-average-sits-at-137-kwh/>. "BNEF's 2020 Battery Price Survey, which considers passenger EVs, e-buses, commercial EVs and stationary storage, predicts that by 2023 average pack prices will be \$101/kWh."

¹⁵ Ibid.

¹⁶ 2020 Climate Report, p. 24: Combustion Turbines – \$550/kilowatt (kW) (represents multi-unit site); Combined Cycle – \$650/kW (represents 2x1 advanced class).

¹⁷ 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>.

¹⁸ \$817,000,000 ÷ 560,000 kW = \$1,459/kW.

declining only slightly to \$964/kW in 2035.¹⁹ Duke Energy's combined cycle capital cost forecast is too low.

The capital cost of the 402 MW Lincoln combustion turbine, the most recent example of a combustion turbine built and owned by Duke Energy, is not public information and was filed with the NCUC under seal.²⁰ For this reason, Powers Engineering assumes the combined cycle cost multiplier of the Asheville combined cycle plant, which is more than double Duke Energy's generic combined cycle cost assumption, also applies to new combustion turbines. This is equivalent to a unit combustion turbine cost of approximately \$1,250/kW,²¹ compared to Duke Energy's assumed combustion turbine cost of \$550/kW. Also, the NREL database referenced by Duke Energy identifies a generic mid-range capital cost for combustion turbines of \$969/kW in 2021, declining only slightly to \$879/kW in 2035.²² Duke Energy's combustion turbine capital cost forecast is too low.

Duke Energy's claim that the battery storage sensitivity case would be *"three to four times above that of the net-zero scenario that utilizes natural gas"*²³ is completely negated when accurate pricing is used for the gas-fired generation and battery storage. The claimed 3x to 4x difference between the cost of the battery storage alternative and the gas-fired alternative is eliminated when the gas capital cost is doubled, to reflect what Duke Energy has actually been paying for gas-fired plants, and the battery storage capital cost is reduced by half to reflect actual lithium battery price decline trends.

Other utilities are embracing battery storage as a cheaper alternative to combustion turbines. NextEra Energy forecasts it will spend \$1 billion on battery storage projects in 2021.²⁴ NextEra Energy is the parent company of Florida Power & Light, which is located in a state where Duke Energy's sister utilities also operate.²⁵ NextEra indicates that *"batteries are now more economic than gas-fired peakers, even at today's natural gas prices."*²⁶

¹⁹ NREL, Electricity Annual Technology Baseline (ATB) Data Download – 2020 ATB Data, "Natural Gas" tab, webpage accessed February 19, 2021.

²⁰ See NCUC Docket No. E-7 Sub 1134.

²¹ Adjusted combustion turbine unit cost: $(\$1,460/\text{kW} \div \$650/\text{kW}) \times \$550/\text{kW} = \$1,235/\text{kW}$.

²² NREL, Electricity Annual Technology Baseline (ATB) Data Download – 2020 ATB Data, "Natural Gas" tab, webpage accessed February 19, 2021.

²³ Duke Energy 2020 Climate Report, p. 3.

²⁴ GreenTech Media, *NextEra looks to spend \$1B on energy storage in 2021*, April 22, 2020: www.greentechmedia.com/articles/read/nextera-energy-to-spend-1b-on-energy-storage-projects-in-2021.

²⁵ Companies owned by NextEra Energy: <https://www.nexteraenergy.com/company/subsidiaries.html>.

²⁶ GreenTech Media, *NextEra looks to spend \$1B on energy storage in 2021*, April 22, 2020.

NextEra also underscores the cost-effectiveness of solar and wind power relative to gas-fired units, stating “gas-fired units . . . still remain in the \$30-\$40 per megawatt-hour (MWh) range [on a levelized basis], versus wind, which is still in the teens in most parts of the country, and then solar in that [mid-\$20s] range.”²⁷ NextEra goes on to state that “it is very, very competitive, looking at renewables versus gas-fired generation.”

Recent publicly available bid information on solar plus battery storage projects supports NextEra’s cost estimates. The City of Boulder (Colorado) issued a Request for Proposals for renewable energy projects for its proposed public utility in July 2020. It prepared a public summary of the numerous responsive bids it received in October 2020.²⁸ The average power purchase agreement bid received for solar plus battery projects was \$30/MWh.²⁹

The gas-turbine production cost range identified by NextEra is accurate for DEC and DEP gas-fired generation. The production cost of DEC and DEP combined-cycle units in 2019 averaged about \$30 per MWh.^{30,31} Combustion turbines have higher production costs than combined cycle plants. The combustion turbine power plant with the lowest production cost among DEC and DEP is the 978 MW Rockingham plant, with a production cost of \$42 per MWh in 2019.³²

In the base case DEC and DEP portfolios in the 2020 IRPs, the predominant form of gas-fired generation Duke Energy proposed to build during the 15-year study period are combustion turbines. It does not make common sense that electric utilities operating in the same markets as Duke Energy are publicly stating now that battery storage is a less expensive alternative to combustion turbines as Duke Energy states battery storage is three to four times more costly than gas-fired generation.

²⁷ Ibid.

²⁸ City of Boulder, Summary of Bids Received in Response to 2020 Request for Proposals: Utility- and Community-Scale Electric Power Supply and Innovative Financing Options, October 7, 2020: https://empowerourfuture.org/wp-content/uploads/2020/10/2020-10-07-Boulder-RFP_Summary_of_Results.pdf.

²⁹ Ibid, p. 2.

³⁰ DEP, 2019 FERC Form 1, April 14, 2020, p. 403.2 (L.V. Sutton), line 35, \$0.035/kWh (\$35/MWh); p. 403.3 (H.F. Lee), line 35, \$0.030/kWh (\$30/MWh). The said DEP FERC Form 1 is attached hereto as **Attachment 3**.

³¹ DEC, 2019 FERC Form 1, April 14, 2020, p. 402.4 (Dan River), line 35, \$0.027/kWh (\$27/MWh); p. 402.4 (Lee CC), line 35, \$0.024/kWh (\$24/MWh); p. 403.3 (Buck CC), line 35, \$0.035/kWh (\$35/MWh). The said DEC FERC Form 1 is attached hereto as **Attachment 4**.

³² Ibid, p. 403.3 (Rockingham), line 35, \$0.043/kWh (\$42/MWh).

B. Duke Energy's 2020 Climate Report Places Artificial Constraints on Solar + Battery Storage

Duke Energy claims that even with a balanced portfolio of wind, solar and energy storage, further additions of renewables above a certain point have diminishing value and ultimately become uneconomic for carbon reduction.³³ Duke Energy then references external studies to support its position. One study appearing in both the 2020 Climate Report and the 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.³⁴

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."³⁵ In this case, Duke Energy benefits from the prestige of a national laboratory report, while defining the terms and scope of the study.

The NREL study 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 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.

The report evaluates 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

³³ Duke Energy 2020 Climate Report, p. 27.

³⁴ 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."

³⁵ Ibid.

curtailed when solar penetration exceeds about 10 percent (8,219 MW). This 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.

However, 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 Scenario 3.

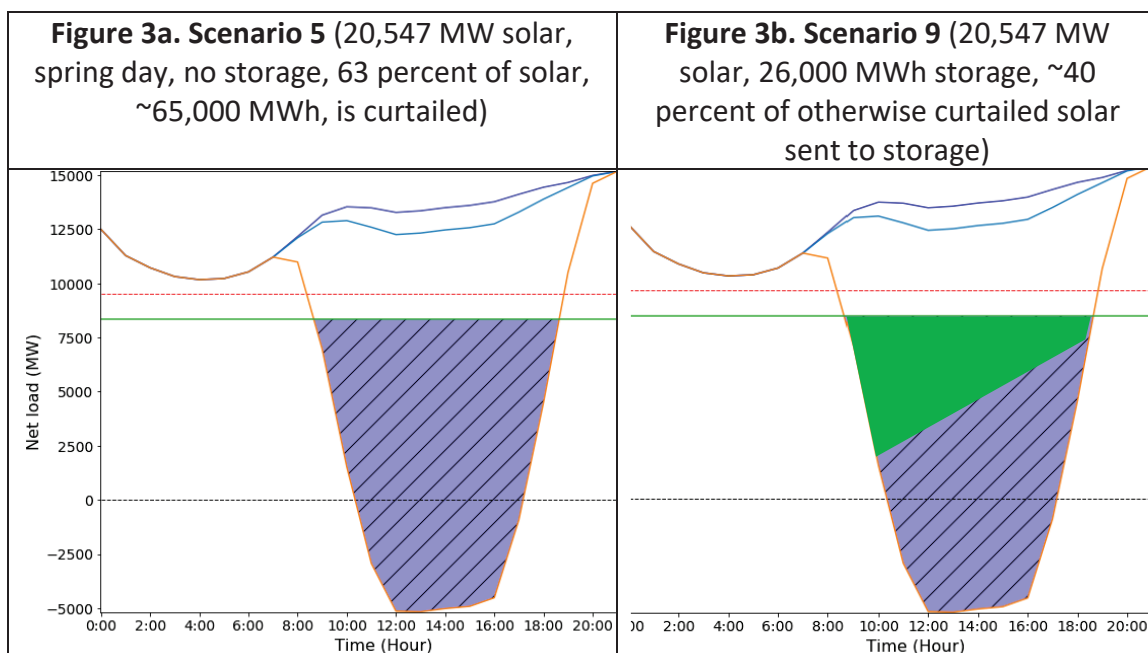
Scenario 9 misstates the ability of storage to fully absorb the excess solar generation by including far too little storage in the scenario. Scenario 9 matches 20,547 MW of solar with 26,000 MWh of storage.³⁶ In spring and fall, solar will produce 4 to 5 MWh per day per MW of capacity.³⁷ In the case 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 3. 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 production – about 65,000 MWh³⁸ – would have to be curtailed. 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 3b, where 40 percent of the otherwise curtailed solar power is directed to storage (green fill).

³⁶ 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.

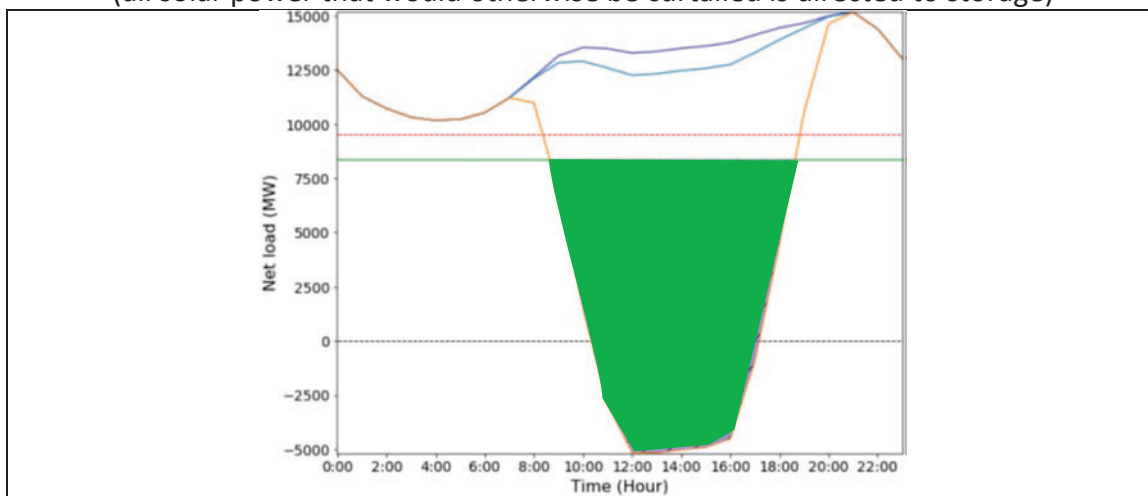
³⁷ NREL PV Watts Calculator, for Raleigh, NC, accessed February 14, 2021: <https://pvwatts.nrel.gov/pvwatts.php>.

³⁸ 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.



What is missing from the NREL study is the scenario that increases battery storage capacity consistent with the amount of solar capacity to eliminate, or nearly eliminate, solar power curtailments under light load spring and fall day conditions. For example, if Scenario 9 was 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 4.

Figure 4. 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 NREL study, paid for by Duke Energy, should not be relied upon by the NCUC as a justification for rejecting solar power and storage as the centerpiece of a carbon-neutral strategy for DEC and DEP 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). This is exclusively an artifact of the limitations placed on the scenarios studied by NREL, 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 4, all of the solar capacity can be put to productive 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 be utilized to meet DEC and DEP demand.

C. National – Federal Objective of Carbon-Free Power Generation by 2035

President Biden issued an executive order on January 27, 2021 to address the climate crisis which includes achieving a carbon-free electric power sector by 2035:³⁹

President Biden set ambitious goals that will ensure America and the world can meet the urgent demands of the climate crisis, while empowering American workers and businesses to lead a clean energy revolution that achieves a carbon pollution-free power sector by 2035 and puts the United States on an irreversible path to a net-zero economy by 2050.

In response to this federal directive, a Modified Early Coal Retirements Portfolio is included in this report that achieves a carbon pollution-free Duke Energy in North Carolina by 2035 (see Section IV below).

D. North Carolina's Proposed Carbon Neutrality in Power Sector by 2050

The 2020 Climate Report notes that North Carolina has a carbon neutrality target similar to that of Duke Energy, stating:⁴⁰

The North Carolina governor recently directed the development of a state Clean Energy Plan that proposes to explore a variety of policies and actions that will seek to reduce carbon emissions, modernize the utility regulatory model and advance clean energy economic development opportunities. The North Carolina Clean Energy Plan calls for a 70 percent

³⁹ 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/>.

⁴⁰ 2020 Climate Report, p. 15.

reduction in greenhouse gas emissions in the power sector by 2030 and aims to achieve carbon neutrality by 2050.

The North Carolina Clean Energy Plan was prepared and issued by the North Carolina Department of Environmental Quality in October 2019 in response to Executive Order 80 signed by Governor Roy Cooper on October 29, 2018.⁴¹

E. Implications of Carbon Neutrality Targets for New Gas-Fired Procurement

Duke Energy asserts in its 2020 Climate Report that “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 only.”⁴² However, the federal government has accelerated the target date for carbon neutrality from power generation to 2035. The total capital costs of new gas-fired generation built in the 2020s could not be recovered from ratepayers by 2035, assuming a 20-year book life. In fact, DEC proposes to bring online all of the combined-cycle capacity included in its base case with carbon policy portfolio, 1,224 MW, in 2035.⁴³ The issue of stranded costs associated with new gas-fired generation, and who will be responsible for those stranded costs, is not addressed by either DEC or DEP in their respective 2020 IRPs.

III. Current DEC and DEP Capacity – Reserves, Demand Growth, DSM

A. Duke Energy Maintains More Capacity Than Necessary for Reliability

Both DEC and DEP include, 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.⁴⁴ 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,⁴⁵ and ten days below 10 percent ORM in DEP territory.⁴⁶ North American Electric Reliability Corporation (“NERC”) requires that

⁴¹ NCDEQ, *North Carolina Clean Energy Plan*, October 2019: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

⁴² 2020 Climate Report, p. 29.

⁴³ DEC 2020 IRP, Table 12-E, p. 100.

⁴⁴ DEC’s 2020 IRP, p. 69; DEP’s 2020 IRP, p. 71.

⁴⁵ DEC’s 2020 IRP, Table 9-A, p. 71.

⁴⁶ DEP’s 2020 IRP, Table 9-A, p. 73.

utilities such as DEC and DEP maintain an ORM of at least 6 percent at all times to assure grid reliability.⁴⁷

The actual ORMs on these peak winter days are compared to the planning reserve margin (PRM) for the respective year. The Duke Energy planning target for the PRM is 17 percent.⁴⁸ 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.⁴⁹ 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.⁵⁰

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.

However, information provided by Duke Energy in response to NC WARN data requests, 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.

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.⁵¹ The original and revised winter peak values are shown in Table 1, along with the original ORM and recalculated ORM.

⁴⁷ 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 Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.”

⁴⁸ DEC’s IRP, p. 69; DEP’s IRP, p. 71.

⁴⁹ Ibid.

⁵⁰ 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.”

⁵¹ DEC-DEP’s Response to SELC’s Data Request 2-12 (see supporting Excel spreadsheet), attached hereto as **Attachment 5**.

Table 1. 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 ⁵²
01/05/18	21,620	8.0	19,077	22.4 ⁵³
1/31/19	18,875	7.2	16,880	19.9 ⁵⁴

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.⁵⁵ Use of the correct winter peak demand for January 5, 2018 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 meaningless 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.⁵⁶ However, Duke Energy then states it assumes that it “will rely on” nearly 30 percent of its reserve margin being met with non-firm supply.⁵⁷ Not only is Table 9-A in the DEC and DEP IRPs inaccurate due to revised winter peak values, the

⁵² $19,151 \text{ MW} \times 1.024 = 19,611 \text{ MW}$. $19,611 \text{ MW} \div 18,275 \text{ MW} = 1.073$ (7.3 percent reserve margin)

⁵³ $21,620 \text{ MW} \times 1.08 = 23,350 \text{ MW}$. $23,350 \text{ MW} \div 19,077 \text{ MW} = 1.224$ (22.4 percent reserve margin)

⁵⁴ $18,875 \text{ MW} \times 1.072 = 20,234 \text{ MW}$. $20,234 \text{ MW} \div 16,880 \text{ MW} = 1.199$ (19.9 percent reserve margin)

⁵⁵ 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.”

⁵⁶ 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.”

⁵⁷ 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.”

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,⁵⁸ 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 combustion turbines, pumped storage, hydro, combined cycle units, 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 2.

Table 2. 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 ⁵⁹ (MW)	Equivalent ORM ⁶⁰ (%)
DEC			
01/05/18	19,077	CT = 1,071 MW pumped storage = 547 MW hydro = 241 MW coal = 49 MW steam = 168 MW <u>DSM = 428 MW</u> 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 <u>DSM = 478 MW</u> Total = 1,462 MW	9.7 (no non-firm imports) 13.7 (non-firm imports add 29% to reserve margin)

⁵⁸ DEC-DEP's Responses to NCWARN-CBD's Data Requests 4-5, attached hereto as **Attachment 6**.

⁵⁹ 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.

⁶⁰ DEC example: $(19,077 \text{ MW} + 2,504 \text{ MW}) / 19,077 \text{ MW} = 1.131$ (13.1%). $13.1\% \div (1 - 0.29) = 18.45\%$.

DEC indicated that its forecast cumulative available capacity in the winter of 2017/2018 was 22,722 MW.⁶¹ 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 only one generator, combustion turbine Lincoln CT 16, 97 MW, was in forced outage on January 5, 2018.⁶² 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,⁶³ without considering the non-firm imports DEC and DEP routinely rely on to supplement 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.⁶⁴ No low ORM winter peak days were reported by DEP in 2019.⁶⁵

Non-firm imports that DEC and DEP rely on to meet the winter peak are always 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.”⁶⁶

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.^{67,68} The PJM summer peak is approximately 20,000 MW higher than the winter peak.⁶⁹ 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, 2018.⁷⁰

⁶¹ NCUC Docket No. E-100, Sub 147, DEC’s 2016 IRP, September 1, 2016, p. 40.

⁶² DEC-DEP’s Responses to NCWARN-CBD’s Data Requests 4-5, attached hereto as **Attachment 6**.

⁶³ $22,675 \text{ MW} \div 19,077 \text{ MW} = 1.186$ (18.6 percent reserve margin)

⁶⁴ DEC-DEP’s Responses to NCWARN-CBD’s Data Requests 4-5, attached hereto as **Attachment 6**.

⁶⁵ DEP’s 2020 IRP, Table 9-A, p. 73.

⁶⁶ DEC’s 2020 IRP, p. 72.

⁶⁷ PJM, *PJM Load Forecast Report*, January 2020, p. 5. See: <https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx>.

⁶⁸ 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.”

⁶⁹ PJM, *PJM Load Forecast Report*, January 2020, p. 5.

⁷⁰ DEC’s 2020 IRP, p. 71 (01/05/18, 21,620 MW); DEP’s 2020 IRP, p. 73 (01/05/18, 15,048 MW).

As a point of comparison, the DEC and DEP IRPs point out that PJM limits non-firm purchases to 3,500 MW.⁷¹ 3,500 MW represents a 20 percent reserve margin on DEC's all-time January 5, 2018 winter peak load.⁷² 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, 2015.⁷³ 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.⁷⁴ 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.⁷⁵ 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.⁷⁶ 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.⁷⁷ For example, New England ISO met about 17 percent of its January 2020 winter peak

⁷¹ DEC's 2020 IRP, p. 72.

⁷² $3,500 \text{ MW} \div 19,070 \text{ MW} = 0.183$ (18.3 percent).

⁷³ Transcript of NCUC Staff Conference, March 2, 2015, attached hereto as **Attachment 7**.

⁷⁴ DEC and DEP's 2020 IRPs, Table 9-A.

⁷⁵ Attachment 7, Transcript of NCUC Staff Conference, March 2, 2015, pp. 11-12. 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."

⁷⁶ NCUC, March 2, 2015 transcript, p. 17. "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."

⁷⁷ 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."

demand with a mix of firm and non-firm imports.^{78,79} This reality should be recognized and 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 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.⁸⁰ Greater reliance on non-firm imports to meet winter and summer peaks, up to and beyond 3,500 MW, would allow acceleration of 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.⁸¹ These non-firm imports were substantial and are shown in Table 3.

Table 3. 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

⁷⁸ 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.

⁷⁹ 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.”

⁸⁰ E.g., DEC’s 2020 IRP, Table 11-A: Ranking of Coal Plants for Retirement Analysis, p. 79.

⁸¹ DEC-DEP’s Responses to NCWARN-CBD’s Data Request 5-3(c) (see Excel spreadsheet produced with the data response). The pertinent spreadsheet is not readily convertible to PDF format for filing. However, NCWARN-CBD can submit the spreadsheet in native Excel format upon request.

explanation of the power supply tools it had at its disposal on that day to assure grid reliability:⁸²

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.”

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:⁸³

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.⁸⁴

B. Forecast Demand Growth Rates Are Substantially Higher Than Actual Trend

DEC and DEP have consistently overestimated demand growth in their respective service territories, as shown in Figure 5.⁸⁵

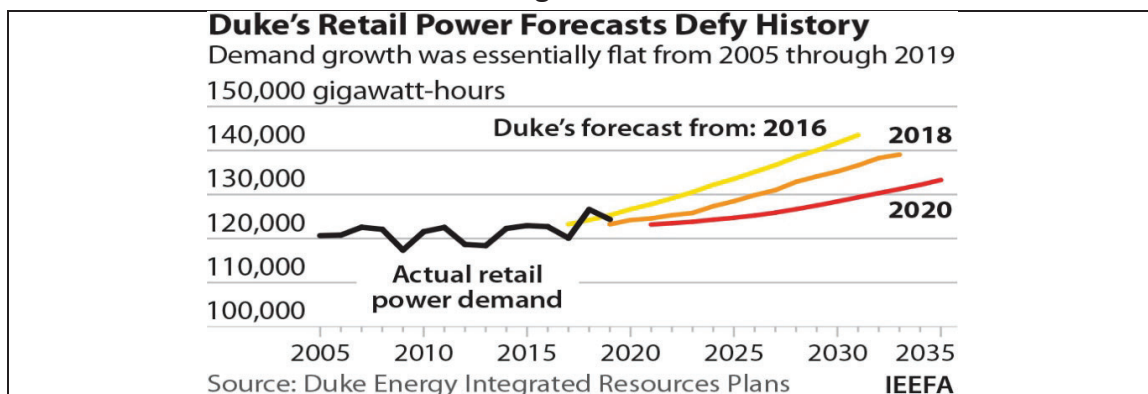
⁸² Attachment 7, Transcript of NCUC Staff Conference, March 2, 2015, p. 17.

⁸³ PJM, *PJM Manual 12: Balancing Operations, Revision: 42*, January 27, 2021, p. 37.

⁸⁴ Attachment 7, NCUC, March 2, 2015 transcript, pp. 11-12.

⁸⁵ 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.

Figure 5. Comparison of Duke Energy actual demand growth to forecast demand growth



1. DEC Forecast Demand Growth Rate

The average actual DEC retail sales growth rate, including residential, commercial, and industrial customers, was 0.2 percent between 2010 and 2019.⁸⁶ The forecast retail sales growth rate, with energy efficiency and DSM applied, is 0.5 percent.⁸⁷ The Duke Energy retail sales growth rate is not supported by actual historical DEC retail demand growth.

DEC is projecting in its base-case resource forecast that its annual residential sales will increase by 1.0 percent per year and will rise by an estimated 4,462 GWh by 2035.⁸⁸ This is equivalent to the output of a new combined cycle (CC) gas-fired plant. A 675 MW combined cycle plant running at a capacity factor of about 75 percent would generate about this amount of electricity on an annual basis.⁸⁹

The other primary component of forecast sales growth is wholesale sales. DEC indicates a wholesale sales growth rate of 5.4 percent in the 2010-2019 period with no explanation.⁹⁰ The only narrative explanation given in the DEC IRP regarding the wholesale contracts does not indicate that wholesale sales growth is a reasonable or likely expectation.⁹¹

⁸⁶ DEC's 2020 IRP, Table C-8, p. 235.

⁸⁷ Ibid, Table C-12, p. 242.

⁸⁸ DEC's 2020 IRP, Table C-9, p. 238.

⁸⁹ 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.

⁹⁰ DEC's 2020 IRP, Table C-8, p. 235.

⁹¹ Ibid, p. 122. "Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area. Over the next five years, DEC has a very small amount of contracts that expire under the current contract terms. The Company will determine the

The assumed increase in DEC base case sales of 8,800 GWh by 2035, driven by residential and wholesale sales, is equivalent to the output of two new 675 MW combined cycle plants.⁹²

2. DEP Forecast Demand Growth Rate

The average actual DEP retail sales growth rate, including residential, commercial, and industrial customers was 0.4 percent between 2010 and 2019.⁹³ The forecast retail sales growth rate, with energy efficiency and DSM applied, is 0.8 percent.⁹⁴ The DEP retail sales growth rate is double the actual historical DEP retail demand growth.

DEP is projecting in its base-case demand growth forecast that its annual residential sales will increase by 0.9 percent per year and will rise by an estimated 4,153 GWh by 2035.⁹⁵ This is equivalent to the output of a new 675 MW combined cycle plant running at a capacity factor of about 70 percent.⁹⁶

The other primary component of forecast sales growth is wholesale sales. DEC indicates a wholesale sales growth rate of 4.3 percent in the 2010-2019 period.⁹⁷ The only narrative explanation given in the DEP IRP regarding the wholesale contracts indicates that they are currently declining.⁹⁸

The assumed increase in DEP base case sales of 8,194 GWh by 2035,⁹⁹ driven by residential and wholesale sales, is equivalent to the output of two new 675 MW combined cycle plants operating at a capacity factor of 70 percent.

feasibility of obtaining additional purchased power arrangements in the future to economically meet customer demand.”

⁹² DEC’s 2020 IRP, Table C-11, p. 240.

⁹³ DEP’s 2020 IRP, Table C-8, p. 226.

⁹⁴ Ibid, Table C-12, p. 233.

⁹⁵ DEP’s 2020 IRP, Table C-9, p. 229.

⁹⁶ $675 \text{ MW} \times 8,760 \text{ hr/yr} \times 0.70 = 4,139,100 \text{ MWh/yr}$.

⁹⁷ DEP’s 2020 IRP, Table C-8, p. 226.

⁹⁸ Ibid, p. 123. “Over the next five years, DEP has approximately 425 MW of purchased power contracts that

expire under the current contract terms. The Company plans to engage the marketplace to determine the feasibility of extending existing contracts or replacing them with other purchased power arrangements to economically meet customer demand. . . {The Company will] continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area.”

⁹⁹ DEP’s 2020 IRP, Table C-11, p. 231.

C. Inadequate Use of Demand Side Management (DSM) Resources at the Winter Peak

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.

DEC had 428 MW of DSM available to meet the winter peak in 2018.¹⁰⁰ However, DEC did not deploy any DSM for that purpose as summarized by NCUC:¹⁰¹ “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 combined cycle power plant.

DEP had 478 MW of DSM available to meet the winter peak in 2018.¹⁰² No DSM was deployed by DEP on January 5, 2018,¹⁰³ 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, 2018.¹⁰⁴ 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.

IV. A Modified “Early Coal Retirement” Portfolio Is The Best Option, with Battery Storage Displacing New Gas-Fired Generation

A. DEC and DEP’s Proposed Portfolios

Duke Energy released its 2020 IRPs for DEC and DEP on September 1, 2020. Each IRP covers DEC and DEP operations in both North Carolina and South Carolina. Six 15-year planning portfolios are presented in each IRP:¹⁰⁵

¹⁰⁰ DEC’s 2019 IRP, September 5, 2018, p. 162.

¹⁰¹ 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.

¹⁰² DEP’s 2018 IRP, p. 156.

¹⁰³ *Ibid*, pp. 253-254.

¹⁰⁴ 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.

¹⁰⁵ DEC’s 2020 IRP, p. 16; DEP’s 2020 IRP, p. 16.

- | | | |
|----|---|-----------------------|
| 1. | Base Case without Carbon Policy | cost: \$79.8 billion |
| 2. | Base Case with Carbon Policy | cost: \$82.5 billion |
| 3. | Earliest Practicable Coal Retirements | cost: \$84.1 billion |
| 4. | 70% CO2 Reduction: High Wind | cost: \$100.5 billion |
| 5. | 70% CO2 Reduction: High SMR (small modular reactor) | cost: \$95.5 billion |
| 6. | No New Gas | cost: \$108.1 billion |

The first five portfolios rely on substantial new gas-fired generation capacity to meet forecast future power needs. New gas-fired capacity in the first five portfolios varies from 6,100 MW to 9,600 MW in the combined DEC/DEP scenarios. The sixth “No New Gas” portfolio has the highest estimated cost—implying that phasing-out new gas generation would be a heavy burden on ratepayers and therefore bad policy.

New transmission cost varies with each portfolio, ranging from \$0.9 billion in the “Base Case without Carbon Policy” and \$1.3 billion in “Earliest Practicable Coal Retirements,” to \$8.9 billion for the “No New Gas” portfolio.

Each scenario is classified as either “Most Economic” coal retirement or “Earliest Practicable” coal retirement. The “Most Economic” retirement schedule is assumed for the two “Base Case” portfolios and the “No New Gas” portfolio. The “Earliest Practicable” coal retirement schedule is assumed for the two “70% Carbon Reduction” portfolios and the “Earliest Practicable Coal Retirements” portfolio. These two coal retirement schedules are shown in Table 4.¹⁰⁶

Table 4. Earliest Practicable Coal Retirement Dates of DEC Coal Plants

TABLE A-11
EARLIEST PRACTICABLE COAL RETIREMENT DATES OF DEC COAL PLANTS

	BASE CASE MOST ECONOMIC RETIREMENT YEAR (JAN 1)	EARLIEST PRACTICABLE COAL RETIREMENT YEAR (JAN 1)	CONSTRAINING FACTOR
Allen 2 – 4	2022	2022	Not Applicable – Retired with Capacity Length
Allen 1 & 5	2024	2024	Transmission project to enable retirement
Cliffside 5	2026	2026	Construction of onsite or offsite capacity
Marshall 1 – 4	2035	2028	Construction of onsite gas capacity
Belews Creek 1 & 2	2039	2029	Construction of onsite gas capacity, interstate pipeline
Cliffside 6	2049	2049*	*Conversion to 100% Gas in 2030, eliminating coal firing capabilities

¹⁰⁶ DEC’s 2020 IRP, p. 175.

The basic concept behind the first five portfolios in the 2020 DEC and DEP IRPs is that new gas generation will substitute for existing coal power, with varying amounts of non-fossil assets added, including solar, wind, storage, nuclear, and EE/DSM, to reach the specified GHG reduction target.

Duke Energy also looked at relying more on imports from neighboring balancing authorities for supply instead of building new generation. The Company estimated a \$4-5 billion expense (by 3rd parties in adjacent balancing areas) to facilitate 5,000 MW in new import capacity, and \$8 - \$10 billion to facilitate 10,000 MW in new import capacity.¹⁰⁷

B. A Sampling of General Problems and Limitations of the Portfolios Presented by Duke Energy

The primary problem with the “70% CO2 Reduction” portfolios and the “No New Gas” portfolio is the heavy reliance on unlikely and expensive forms of non-fossil power, specifically: offshore North Carolina wind power, small modular (nuclear) reactors (SMR), and 1,600 MW of new pumped hydro in the “No New Gas” portfolio.¹⁰⁸

Solar, and solar with battery storage, are also artificially capped by Duke Energy’s IRP model at 300 MW per year addition rate in DEC, and 200 MW per year in DEP.¹⁰⁹

Duke Energy projects only a modest increase in behind-the-meter (BTM) rooftop solar over the 15-year planning horizon, about 88 MW per year in DEC and 44 MW per year in DEP.¹¹⁰ The new (post-2020) rooftop solar capacity in DEC would reach 1,327 MW by 2035, and in DEP 664 MW, for a total of about 2,000 MW.

C. Modified Earliest Practicable Coal Retirement Portfolio

Achievement of the above-described carbon-neutral goals, *supra* Sections II.A, II.C. and II.D, requires rapid retirement of Duke Energy’s coal fleet and elimination of new gas from Duke Energy’s resource planning. The best approach to meet those objectives affordably is a modification of Portfolio C (“Earliest Practicable Coal

¹⁰⁷ Ibid, p. 58.

¹⁰⁸ Ibid, p. 94.

¹⁰⁹ DEC’s 2020 IRP, pp. 39-40. “Consistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 300 MW per year over the planning horizon in DEC.”; DEP 2020 IRP, p. 40. “Consistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 200 MW per year over the planning horizon in DEP.”

¹¹⁰ DEC and DEP’s 2020 IRPs, Table C-4.

Retirements”) that replaces that portfolio’s new gas-fired generation with battery storage, as outlined below.

Portfolio C retires all coal firing in the 2020s. It also includes 9,600 MW of new gas generation, 1,350 MW of onshore wind in Central North Carolina, and relatively modest levels of solar, battery storage, and EE/DSM compared to the “No New Gas” portfolio.

The “Modified Earliest Practicable Coal Retirements” portfolio described and recommended herein combines increased deployment of solar and battery storage with the rapid phase-out of coal. The rate of rooftop solar deployment would also be increased in the alternate portfolio to reflect best demonstrated practice, using best-in-class U.S. utility performance as the standard, and battery storage would be paired with the rooftop solar. The original energy efficiency and demand response targets would be retained. Finally, the 100 percent carbon-free electricity target is accelerated to 2035, consist with President Biden’s January 27, 2021 executive order. The Modified Earliest Practicable Coal Retirements portfolio is shown in Table 6 below, along with the two Base Case portfolios and the Earliest Practicable Coal Retirements portfolio.

A challenge in determining the quantities, in MW, of the elements of the Modified Earliest Practicable Coal Retirements Portfolio is that the 2020 IRPs include DEP and DEC demand in 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.¹¹¹ A retail sales growth of 0.3 percent per year was assumed, consistent with the average of the 2010-2019 DEC and DEP actual retail sales growth rates, to estimate combined 2035 DEC and DEP retail sales in North Carolina of 100,800,000 MWh.¹¹²

Both the DEC and DEP IRPs state that about one-half of retail sales are met with nuclear power.¹¹³ 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. If this non-nuclear carbon-free energy is exclusively solar power, approximately 27,000 MW of new solar capacity will need to be installed in North Carolina by 2035.¹¹⁴

¹¹¹ 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.

¹¹² $96,399,570 \text{ MWh} \times (1.003)^{15} = 100,829,843 \text{ MWh}$.

¹¹³ *E.g.*, DEC’s 2020 IRP, p. 75.

¹¹⁴ 1 MW of installed solar capacity produces about 1,500 MWh per year of solar energy. There is approximately 7,000 MW of existing solar capacity in North Carolina, producing about 10,000,000 MWh

This would require about 100,000 MWh of new battery storage to largely eliminate solar production curtailments,¹¹⁵ 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 proposed “Modified Earliest Practicable Coal Retirements” portfolio, with battery storage added to the nearly 7,000 MW of existing utility-scale solar in North Carolina to replace combustion turbines,¹¹⁶ the addition of battery storage to all new utility-scale solar, and an expanded BTM solar and storage target, will be less than the unmodified “Earliest Practicable Coal Retirements” portfolio. This is in significant part because a substantial portion of this portfolio will be owned by private third-parties, either utility-scale solar owners or residential and commercial customers installing BTM rooftop systems. These private investments will not be added to Duke Energy’s rate base.

Duke Energy provides total Present Value Revenue Requirement (PVRR) costs for each portfolio presented in the DEC and DEP 2020 IRPs, but provides no details in the public versions of the IRPs on the capital cost assumptions for the technologies included in the portfolios. For this reason, the capital costs of the combined Earliest Practicable Coal Retirements Portfolio included in the IRPs and the Modified Earliest Practicable Coal Retirements Portfolio proposed in this report are compared to determine the relative cost of the two portfolios. As shown in Table 5, the total capital cost associated with the generation in the combined Modified Earliest Practicable Coal Retirements Portfolio presented in this report is about \$6 billion less than the capital cost of the generation in the combined Earliest Practicable Coal Retirements Portfolio.

per year. Therefore, sufficient new solar capacity to generate 40,000,000 MWh per year must be added.
 $40,000,000 \text{ MWh/yr} \div 1,500 \text{ MWh/MW} = 26,667 \text{ MW}$.

¹¹⁵ Due to the high percentage of BTM solar in this portfolio, a significant portion of the solar energy produced in the portfolio would be used onsite in real-time and not require storage.

¹¹⁶ The battery storage is assumed to have 4-hour duration to serve as a substitute for a combustion turbine, such that 7,000 MW of battery storage is equivalent to $4 \text{ hr} \times 7,000 \text{ MW} = 28,000 \text{ MWh}$ of battery storage capacity.

Table 5. Comparison of Total Capital Cost of Generation in the Duke Energy Combined Earliest Practicable Coal Retirements Portfolio and the Modified Portfolio

Technology (Duke Energy to own)	Earliest Practicable Coal Retirements			Modified Earliest Practicable Coal Retirements		
	Quantity (MW)	Unit cost (\$/MW)	Total cost (\$MM)	Quantity (MW)	Unit cost (\$/MW)	Total cost (\$MM)
solar	8,475	900,000	7,630	12,400	900,000	11,160
wind	1,350	1,300,000	1,755	0	0	0
storage	2,200	400,000 (4-hr storage)	880	12,400	400,000	4,960
gas turbine	9,600	1,250,000	12,000	0	0	0
Total cost:			22,265			16,120

Source of capital cost estimates: 1) solar and wind, Duke Energy 2020 Climate Report (p. 25); storage, Bloomberg (\$100/kWh); gas turbine, 2020 Climate Report (p. 25, CT) x Asheville CC multiplier of 2.25x (\$1,250/kW).

In the Modified Portfolio, battery storage and solar power will also serve as default alternatives to the Central North Carolina wind power elements of the “Earliest Practicable Coal Retirements” portfolio. What this means in practical terms is that the Central North Carolina wind power may or may not be constructed, but the capacity represented by that wind power is included in the Modified Portfolio as solar power. The Modified Earliest Practicable Coal Retirements Portfolio is shown in Table 6 along with the Base Case, Base with Carbon Policy, and Earliest Practicable Coal Retirements Portfolios.

Table 6. Modified Earliest Practicable Coal Retirements Portfolio

	Base without Carbon Policy		Base with Carbon Policy		Earliest Practicable Coal Retirements		Modified Earliest Practicable Coal Retirements: Proposed by NC WARN & The Center	
PORTFOLIO	A		B		C		D	
System CO ₂ Reduction (2030 2035) ¹	56%	53%	59%	62%	64%	64%	80%	100%
Present Value Revenue Requirement (PVR) [\$B] ²	\$79.8		\$82.5		\$84.1		< \$84.1 (only Duke Energy capital costs included)	
Estimated Transmission Investment Required [\$B] ³	\$0.9		\$1.8		\$1.3		\$1.3	
Total Solar [MW] ^{4, 5} by 2035	8,650		12,300		8,475 new (+3,925 MW existing)		12,400 MW new utility 15,000 MW new customer, (all w/4-hr battery storage)	
Incremental Onshore Wind [MW] ⁴ by 2035	0		750		1,350		0	
Incremental Offshore Wind [MW] ⁴ by 2035	0		0		0		0	
Incremental SMR Capacity [MW] ⁴ by 2035	0		0		0		0	
Incremental Storage [MW] ^{4, 6} by 2035	1,050		2,200		2,200		7,000 MW (retrofit 4-hr battery storage, owned by existing 3 rd party solar owners)	
Incremental Gas [MW] ⁴ by 2035	9,600		7,350		9,600		0	
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW] ⁷ by 2035	2,050		2,050		2,050		2,050	
Remaining Dual Fuel Coal Capacity [MW] ⁴ by 2035	3,050		3,050		0		0	
Coal Retirements	Most Economic		Most Economic		Earliest Practicable		Earliest Practicable ⁸	

¹Combined DEC/DEP System CO₂ Reductions from 2005 baseline²PVRs exclude the cost of CO₂ as tax. Including CO₂ costs as tax would increase PVRs by ~\$11-\$16B. The PVRs were presented through 2050 to fairly evaluate the capital cost impact associated with differing service lives³Represents an estimated nominal transmission investment; cost is included in PVR calculation⁴All capacities are Total/Incremental nameplate capacity within the IRP planning horizon⁵Total solar nameplate capacity includes 3,925 MW connected in DEC and DEP combined as of year-end 2020 (projected)⁶Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro⁷Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour⁸Most Economic retirement dates: Cliffside 6 gas-only beginning 2022, all other coal retired 2022, replaced to the extent justifiable on reliability grounds, with seasonal (winter & summer) firm imports via bilateral contracts with existing CC or advanced CT plants in neighboring balancing areas.

1. Substitute Imported Power for Duke Energy Coal Power

All currently operational coal units will be permanently phased-out in 2022. This will be achieved by permanently switching Cliffside Unit 6 to natural gas only in 2022. The remaining coal capacity will be displaced with firm or non-firm imports from adjacent balancing authorities. There is also currently nearly 50,000 MW of low-cost merchant capacity in the PJM Interconnection regional market,¹¹⁷ with substantial available capacity,¹¹⁸ adjacent to DEC and DEP territories. Some of this capacity could be contracted by Duke Energy on a firm bilateral seasonal basis, winter and summer, to substitute for DEC and DEP coal power.

A major advantage to this approach would be the substantially lower cost of production of combined cycle plants compared to coal plants, and therefore lower costs to Duke Energy ratepayers. The cost of production of Duke Energy's coal plants is \$40/MWh and higher.¹¹⁹ Two coal plants, Allen and Mayo, have production costs of more than \$60/MWh.¹²⁰ In contrast, the cost of production of combined cycle plants averages about \$30/kWh.¹²¹

2. Retrofit Battery Storage to Existing Utility-Scale Solar for Peaking Power

A lower-cost peaking power opportunity for DEC and DEP is to retrofit battery storage to the nearly 7,000 MW of existing solar facilities in North Carolina as a substitute for the proposed combustion turbines.¹²² This existing solar capacity is already deliverable on existing transmission lines. Locating battery storage at the existing solar sites would minimize solar curtailments and would allow expansion of solar development on those same circuits.

¹¹⁷ 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.

¹¹⁸ 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.

¹¹⁹ DEC 2019 FERC Form 1, April 14, 2020, p. 402, line 35 (Belews Creek, \$40.60/MWh; Marshall, \$42.30/MWh), p. 403, line 35 (Allen, \$68.00/MWh), p. 403.1, line 35 (Cliffside, \$39.80/MWh); DEP 2019 FERC Form 1, April 14, 2020, p. 402.1, line 35 (Roxboro, \$47.90/MWh), p. 403, line 35 (Mayo, \$60.80/MWh).

¹²⁰ See footnote 121.

¹²¹ See footnotes 30 and 31.

¹²² 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.

Duke Energy has been directed by the NCUC to work with stakeholders to enable retrofitting battery storage at existing solar sites in North Carolina.¹²³ 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.”¹²⁴ Duke Energy has “studied the impact of replacing CTs with 4-hour battery storage during various points over the planning horizon.”¹²⁵ Workshops on retrofitting battery storage to existing solar sites have been held and Duke Energy has produced a stakeholder report with recommendations.

The workshop stakeholders, as of September 2020, reached consensus on key areas associated with adding storage to existing solar facilities, with some substantive issues (contract term, metering) yet to be resolved.¹²⁶ 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.¹²⁷

3. Expand Behind-the-Meter Solar and Battery Storage

North Carolina has less than 200 MW of BTM solar.¹²⁸ California has installed over 10,000 MW of BTM solar, with 6,000 MW installed in the last five years alone.¹²⁹ Many of the most recent installations include battery storage. This large amount of BTM solar has been installed under the same contractual conditions as currently exist in North Carolina: net-metering with a monthly fixed charge of \$10-\$15 per month.

Matching the demonstrated California BTM solar installation rate of 1,200 MW per year in North Carolina, over the 15-year IRP planning horizon, would add about 15,000 MW of new solar and battery storage in the state.¹³⁰

¹²³ 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.”

¹²⁴ 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.

¹²⁵ DEC’s 2020 IRP, p. 161.

¹²⁶ NCCEBA, NCSEA, SELC, *Reply Comments, supra*, p. 13.

¹²⁷ *Ibid*, p. 10. “The solar-plus-storage resource can help avoid the cost of expensive new peaking capacity, . . .”

¹²⁸ EIA, *State Electricity Profiles – North Carolina Electricity Profile 2019*, Table 11. Net Metering, November 2, 2020: <https://www.eia.gov/electricity/state/northcarolina/>.

¹²⁹ California Distributed Generation Statistics, Statistics and Charts, webpage accessed February 21, 2021: <https://www.californiadgstats.ca.gov/charts/>.

¹³⁰ This assumes ramping-up at 200 MW/yr over the first 5 years, achieving 1,200 MW/yr in Year 6, and holding that 1,200 MW/yr installation rate from Years 6 to 15.

This distributed solar and storage has benefits to the grid far beyond the power it generates. The major and extended blackouts across Texas and the Midwest in February 2021 underscore the importance of onsite battery storage to counter unforeseen emergency events that disable the grid and leave customers without power.

Aggregating battery storage into virtual power plants (VPPs) increases the value to the customer and the grid of BTM batteries. VPPs take advantage of advanced communications to aggregate hundreds or thousands of individual customer batteries electronically to act as if they were a single “virtual” large battery. The VPP can be scheduled and dispatched as if it were a traditional peaking power plant, and can obtain the revenue streams associated with this capability, while at the same time providing back-up power reliability in the homes and businesses where the batteries are located.

An example is the successful Green Mountain Power (GMP) VPP in Vermont. GMP began offering retail customers 13.5 kWh battery storage units for \$15 per month in 2017.¹³¹ The revenue to be generated by participation in the VPP enabled GMP to sell these battery storage units to customers for \$1,500, about 20 percent of the \$7,000 full installed capital cost of the battery.¹³² This VPP project reached its full build-out of 2,000 residential units in 2019. The project is meeting revenue expectations.¹³³

GMP saved \$500,000 during a July 2018 heat wave by dispatching 500 of these Tesla Powerwall™ batteries to operate as a VPP.¹³⁴ On a unit basis, GMP saved \$1,000 per battery during this heat wave. The savings were obtained by reducing the peak load for all GMP customers, and thereby reducing the demand for power, at a time when the cost of power was very high. Tesla introduced a software update in 2018 that allows its Powerwall™ to be optimized for charging and discharging on time-of-use rates.

Finally, both DEC and DEP should also be required by the NCUC to establish robust on-bill tariffs open to unlimited private capital, with payment tied to the meter,

¹³¹ The customer can own the Tesla Powerwall after 10 years of payments. The customer also has the option to make a one-time upfront \$1,500 payment to purchase the unit outright.

¹³² Electronic communication between B. Powers, Powers Engineering, and J. Castonguay, Chief Innovation Officer, Green Mountain Power, October 26, 2017. Installed all-in cost of 13.5 kWh Powerwall is about \$7,000 on average.

¹³³ Green Mountain Power, *GMP – Grid Transformation Innovative Pilot – Update*, prepared for Vermont Public Utility Commission, April 15, 2019, p. 3.

¹³⁴ Utility Dive, *Tesla batteries save \$500K for Green Mountain Power through hot-weather peak shaving*, July 23, 2018. See: <https://www.utilitydive.com/news/tesla-batteries-save-500k-for-green-mountain-power-through-hot-weather-pea/528419/>. Tesla completed the 2,000-unit Powerwall™ deployment in 2019.

not to the customer. Such an on-bill tariff program would greatly expand access to BTM solar and storage among lower-income North Carolinians.

Large-scale investor-owned utility on-bill financing and on-bill repayment programs with a proven track record are operational, and could serve as a model for use with DEC and DEP customers to expand BTM solar and storage access among lower-income customers. The Hawaii on-bill program is available to owners and renters.¹³⁵ Repayment is tied to the electric meter and not to the individual customer. The program leverages its bond funding with private capital, with a typical project consisting of a roughly 50/50 split between bond funding and private capital.¹³⁶

V. Conclusion

The continued indefinite use of coal and gas-fired power in the Duke Energy IRP portfolios is a major weakness in the six portfolios examined in the IRPs. Coal power is no longer baseload power in Duke Energy's supply portfolio. It is serving seasonal or peaking power needs. All currently operational coal units can be permanently phased-out in 2022.

The coal power is unneeded. Duke Energy is maintaining excessive reserve margins at times of peak load particularly when non-firm imports, which Duke Energy relies on in part to serve as reserves for this purpose, are accounted for. For example, 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.¹³⁷ Neighboring balancing areas, especially PJM, have excess reserves and ample generation capacity to substitute for Duke Energy coal power to meet winter peak demand.

Battery power is a lower-cost and more versatile alternative than combustion turbines to meet peak and seasonal demand going forward. This report describes a Modified Earliest Practicable Coal Retirements portfolio. The primary modification to the Earliest Practicable Coal Retirements portfolio in the Duke Energy IRPs is the substitution of battery storage, at existing utility scale solar sites, for gas-fired capacity, and the inclusion of battery storage with all new solar capacity added. The firm seasonal

¹³⁵ Greentech Media, *Hawaii's On-Bill Financing Program Unlocks Energy Upgrades for the Masses*, June 10, 2019. See: <https://www.greentechmedia.com/articles/read/justin-hawaii>.

¹³⁶ Telephone communication between B. Powers and G. Yamamoto, Executive Director - Hawaii Green Infrastructure Authority, August 19, 2020.

¹³⁷ DEC-DEP's Responses to NCWARN-CBD's Data Requests 4-5, attached hereto as **Attachment 6**.

import power contracts for combined cycle capacity in PJM can be discontinued when sufficient battery capacity is online to substitute for this imported power.

A second modification is expansion of the BTM solar and battery storage component of the portfolio. The cost of the BTM solar and storage capacity will be borne by the customers who install it, and will not be rate-based by Duke Energy. As a result, reliance on BTM solar and storage will lower the cost to Duke Energy customers of achieving 100 percent carbon-free electricity. Both DEC and DEP should also be required by the NCUC to establish robust on-bill tariffs open to unlimited private capital, with payment tied to the meter, not to the customer. Such an on-bill tariff program would greatly expand access to BTM solar and storage among lower-income North Carolinians.