STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH
DOCKET NO. E-100, SUB 165

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2020 Integrated Resource Plans And Related 2020 Compliance Plans	))))	ATTORNEY GENERAL'S OFFICE CORRECTED INITIAL COMMENTS ON DUKE'S INTEGRATED RESOURCE PLANS

The North Carolina Attorney General's Office (AGO) respectfully submits these corrected initial comments regarding the 2020 Integrated Resource Plans for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) (referenced together as Duke).

I. BACKGROUND AND INTRODUCTION

This proceeding investigates utility proposals for meeting electric power requirements in North Carolina over the next fifteen (15) years (the planning period) using "the least cost mix of generation and demand-reduction measures" that will provide adequate, reliable electric service.[1] All "potential resource options and combinations of resource options to serve its system needs" must be considered.[2] Furthermore, utility proposals "should take into account, as applicable, system operations, environmental impacts, and other qualitative factors."[3]

The Commission uses these utility proposals to analyze the State's overall,

[1] N.C. Gen. Stat. §§ 62-2(a)(3a) (establishing, in quoted text, this policy of the State); 62-110.1(c) (calling for this proceeding).
[2] NCUC Rule R8-60(g).
[3] *Id.*

long-range energy needs.[4] These include “future growth of the use of electricity,” “needed generating reserves,” “the mix and general location of generating plants,” and “arrangements for pooling power.”[5] The Commission “shall consider [this needs] analysis in acting upon any petition by any utility for construction.”[6]

Therefore, the IRP process requires the utility to propose its long term energy vision and strategy. The Commission reviews these proposals and, after consulting with stakeholders, prepares an analysis of the State’s overall, long-term energy needs.

Critical issues to be addressed during the IRP process include: how much electricity consumers will need; when will they need that electricity; how will they use that electricity; and how their needs will evolve over time. Accordingly, a utility must propose how it will affordably address and respond to those needs through: the construction of new power plants; sharing and purchasing energy from neighboring utilities; grid infrastructure investments; energy conservation, and peak demand reduction. Moreover, an IRP must take into account environmental and health-related impacts. These attendant risks not only bear upon a utility’s express requirement to consider “environmental impacts,”[7] but could also result in increased costs.

For instance, there can be environmental impacts and increased costs if an IRP relies too heavily on fossil fuels or fails to account for technological developments in the clean energy sector. Technological and regulatory

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[4] N.C. Gen. Stat. § 62-110.1(c).
[5] *Id.*
[6] *Id.*
[7] NCUC Rule R8-60(g).

developments could make recently built gas plants obsolete. This in turn would likely result in significant consumer costs. Furthermore, decisions regarding whether – and when – a new gas plant is built or a coal plant is retired can have ramifications for local communities and businesses. In short, key decisions surrounding the IRP can have profound cost, distributional, and environmental consequences.

Unfortunately, Duke's 2020 IRPs contain a variety of methodological flaws that, if not corrected, will likely increase ratepayer costs. These flaws will also likely bias the State's resource portfolio in favor of fossil fuels.[8] While Duke's IRPs improve upon certain deficiencies identified in prior Commission proceedings, they are nonetheless inconsistent with the North Carolina Clean Energy Plan.[9] Moreover, they are contrary to the climate objectives of Duke Energy's net zero goal.[10]

These initial comments discuss three core flaws in Duke's IRPs – which have been identified by the AGO's expert, Strategen Consulting, LLC (Strategen),[11] and are discussed in more detail below.

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[8] *Effects of Climate Change on the Southeast*, NORTH CAROLINA CLIMATE OFFICE, https://climate.ncsu.edu/edu/Impacts (last visited Feb. 19, 2021).

[9] NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, STATE ENERGY OFFICE, NORTH CAROLINA CLEAN ENERGY PLAN 12 (2019), https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf (calling on State's power sector to reduce its "greenhouse gas emissions by 70% below 2005 levels by 2030"). The Clean Energy Plan also proposes carbon neutrality by 2050. *Id.*

[10] *Duke Energy aims to achieve net-zero carbon emissions by 2050*, DUKE ENERGY (Sept. 17, 2019), https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050.

[11] Strategen, a California firm, is comprised of a team of well-respected leaders with technical, regulatory, product, and organizational expertise in energy markets, who have decades of experience working closely with governments, utilities, research institutions, technology providers, project developers, and large energy users to evaluate, analyze,

A. First, Duke should use a computer model to retire its coal units economically. Duke's multi-step process for selecting coal unit retirements is overly complicated. It lacks objectivity. It is not fully transparent. Other utilities use computer models that determine the generation needed for grid reliability while simultaneously selecting coal retirements. In contrast, Duke's process uses flawed assumptions to select the most economic retirement dates. Duke then incorporates these pre-selected dates into a model, but by then, the process has been inexorably skewed. This approach will likely prolong Duke's reliance on its coal fleet, to the detriment of ratepayers and the environment. The AGO recommends that the Commission require Duke to:

- Utilize a computer model that can economically retire coal.
- If necessary, retirements under this model could be delayed to secure regulatory approvals or address other justifiable contingencies.

B. Second, increased power sharing with other utilities (neighbor assistance) reduces the costs of maintaining grid reliability. Duke should explore those benefits and identify measures to increase neighbor assistance. Duke projects that it may need to build expensive new fossil fuel generation for grid reliability. Duke would incur significant capital costs building these plants, which it would then seek to recover from its customers. However,

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and implement strong regulatory and policy strategies. The AGO submits Strategen's memorandum for the Commission's consideration.

PJM[12] and many other neighboring utilities have ample, excess generation. These utilities may not encounter reliability issues at the exact same time as Duke. They may not need to shut down their plants for maintenance at the same time as Duke. Therefore, these neighboring utilities could enter into exchange agreements to provide Duke with power from their existing power plants. Neighbor assistance would ensure Duke has sufficient power for grid reliability. If enough utilities could share their power with Duke, Duke could potentially avoid needing to build new fossil fuel plants. Therefore, increased neighbor assistance could potentially reduce the amount of new fossil fuel generation needed for grid reliability. This would have the added benefit of decreasing capital costs. The AGO recommends that the Commission require Duke to:

- Conduct more extensive studies into increased neighbor assistance.
- Identify options that increase neighbor assistance, provided that increased neighbor assistance reduces the need for additional fossil fuel plants.

C. Third, Duke makes several flawed assumptions regarding the value, costs, and difficulty of adding additional, clean energy resources. Duke's modeling assumes that 2-hour storage has relatively low value. Duke also fails to consider how increased forms of certain energy conservation and reduction

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[12] PJM is a regional transmission organization (RTO) that coordinates movement of wholesale electricity in all or parts of thirteen (13) states, including North Carolina, and the District of Columbia.

(demand side management, or DSM) might increase the value of solar. Lastly, Duke's modeling erroneously assumes low solar and wind interconnection rates over the next fifteen years. These flaws in clean energy valuation, if not addressed in this proceeding, will lead to a self-fulfilling prophecy that hinders proper consideration of cleaner energy resources. The AGO recommends that the Commission require Duke to:

- Revisit the cost, value, and deployment assumptions that appear to constrain the integration of additional, alternative resources.
- Evaluate the interplay between winter DSM and solar.

In addition, the AGO expects that the initial comments of other stakeholders will raise other important improvements to Duke's proposals. On reply, the AGO expects to provide comments on, and support for, points raised by stakeholders at the initial comments stage.

II. STANDARD OF REVIEW

Under State law, "any [public] utility in North Carolina may submit to the Commission its proposals as to the future needs for electricity to serve the people of the State or the area served by such utility."[13]

The framework for submitting these proposals is set forth in Commission Rule 8-60. It requires public utilities to forecast the following: their 15-year load requirements; the supply-side and demand-side resources expected to satisfy those loads; and the reserve margin that would be produced.[14] In addition, public

[13] N.C.G.S. § 62-110.1(c).
[14] *Id.*

utilities must provide a comprehensive analysis of all resource options (supply- and demand-side) for satisfaction of those requirements.[15] Utilities submit biennial[16] proposals and other required information. In response, other interested parties may file alternative proposals, submit an evaluation of or comments on the utility proposals, or seek an evidentiary hearing.[17] During the IRP process, "the Attorney General may attend or be represented at any formal conference conducted by the Commission."[18]

After receiving these submissions, the Commission may direct further action.[19] An example of the Commission directing further action can be found in the 2019 IRP Order.[20] There, the Commission directed Duke to identify the earliest date by which its coal fleet could be retired:

> [T]he Commission nonetheless finds good cause to direct that for their 2020 IRPs DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company's existing coal-fired generating units are retired by the earliest practicable date. . . . The "earliest practicable date" shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified in the quoted passage above.[] In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions. The Companies shall include an analysis that compares the alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system

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[15] *Id.*
[16] Update reports are required for review in each year when the biennial reports are not filed. NCUC Rule R8-60.
[17] NCUC Rule R8- 60(h), (k).
[18] N.C.G.S. § 62-110.1(c).
[19] *See, e.g.*, Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans In the Matter of 2019 Biennial Integrated Resource Plans and Related 2019 REPS Compliance Plans issued 6 April 2020 In Docket No. E-100, Sub 157 (2019 IRP Order).
[20] *See id.*

costs, and operational and environmental performance.[21]

From the reports, comments and other evidence in the proceeding, the Commission determines the sufficiency of the information provided as well as the reasonableness of the utility proposals.[22] As is the case in other proceedings, the policy declarations set forth in N.C.G.S. § 62-2(a) inform the Commission's review. These express statutory policies include, but are not limited to, the following: (1) promoting "adequate, reliable, and economical utility service to the general public"; (2) assuring that the "resources necessary to meet future growth . . . include use of the entire spectrum of demand-side options"; and (3) encouraging and promoting "harmony between public utilities, their users and the environment."[23]

III. DUKE'S METHODOLOGICAL FLAWS WILL INCREASE COSTS AND BIAS THE STATE'S RESOURCE PORTFOLIO IN FAVOR OF FOSSIL FUELS IF NOT CORRECTED

A. Duke Should Use an Objective Computer Model to Retire Coal Economically.

1. Duke's Modeling Projects that Many of its Coal Units Will Operate Well into the 2030s.

In response to the 2018 and 2019 IRP Orders regarding evaluation of coal retirements, Duke has identified what it believes are the economic and the earliest practicable retirement dates for its 9,182 Megawatts (MW) of coal.[24] Pursuant to

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[21] *Id*.
[22] *See, e.g.*, *id.*
[23] N.C.G.S. § 62-2(a)(3), (3a), (5).
[24] See Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses issued 27 August 2019 In Docket No. E-100, Sub 157 (2018 IRP Order); 2019 IRP Order. DEC and DEP operate their coal plants separately but are subject to a joint dispatch agreement. These plants were analyzed accordingly in each IRP. *See* DUKE ENERGY CAROLINAS, NORTH CAROLINA

the 2018 IRP Order, Duke was directed to identify the economic retirement dates for its coal units by modeling their continued operation under least cost principles and removing any assumption that those units would remain in service until fully depreciated.[25] Then, in the 2019 IRP Order, the Commission directed Duke to prepare scenarios that identified the "earliest practicable date" for retirement of its coal units, as a means of determining whether greater carbon reductions could be achieved through accelerated coal unit retirements.[26] The coal retirement requirements in the 2019 IRP Order, which build upon the 2018 IRP Order, obligate Duke to assess coal retirements in accordance with "the more rigorous IRP process."[27]"

Despite the Commission's coal retirement directives, Duke's modeling envisions many of its coal assets operating well into the 2030s.[28] As expert analysis suggests,[29] elements of Duke's coal retirement analysis do not appear to reflect the rigor of the IRP process. Other elements of Duke's analysis do not appear to be based on reasonable assumptions or the best available current knowledge regarding implementation considerations. Lastly, Duke has at times failed to "explicitly identify all material assumptions [and] the procedures used to

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INTEGRATED RESOURCE PLAN 2020 79 (2020) (DEC IRP REPORT) (noting that "the ranking of assets for retirement was evaluated across the [two] utilities"); DUKE ENERGY PROGRESS, NORTH CAROLINA INTEGRATED RESOURCE PLAN 2020 81 (2020) (DEP IRP REPORT) (noting the same).

[25] 2018 IRP Order at 90.

[26] 2019 IRP Order at 8.

[27] *Id*.

[28] Indeed, Duke projects that a few of its coal assets will be in operation into the 2040s.

[29] Memorandum from Strategen on its Analysis of the Duke Energy 2020 Integrated Resource Plans to the AGO 5-9 (Mar. 1, 2021) (on file with the Commission) (Strategen Memo).

validate such assumptions."[30] To put this in more concrete terms, Duke's four-step retirement analysis appears to conflict with sound resource planning principles. Duke has failed to provide sufficient context and support for some of its retirement assumptions. Furthermore, some of its assumptions appear to unnecessarily delay retirement, to the detriment of ratepayers.

2. Operating Coal Plants Longer than Necessary Imposes Significant Costs on Customers.

The continued operation of Duke's coal plants imposes significant costs on customers. For example, Strategen estimates that DEC would need to recover **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** in coal costs through 2035 from ratepayers. DEP on the other hand would need to recover **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** during that same period.[32] This amounts to approximately **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** of DEC's generation costs. For DEP, it amounts to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** However, coal is projected to provide just **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** of DEC

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[30] 2019 IRP Order at 8.

[31] Calculated by Strategen based **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** using a discount rate of 6.26%.

[32] Calculated by Strategen based **BEGIN CONFIDENTIAL** [redacted], **END CONFIDENTIAL** using a discount rate of 6.26%.

[33] Strategen calculated this figure by using the DEC IRP's "Base Planning Without Carbon Policy" scenario and comparing the PVRR of the coal costs set forth in **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** with the PVRR through 2035 of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** for DEC.

[34] Strategen calculated this figure by using the DEP IRP's "Base Planning Without Carbon Policy" scenario and comparing the PVRR of the coal costs set forth in **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** for DEP.

[35] Strategen calculated this by using the capacity factors provided in response to **BEGIN**

customers' energy needs and **BEGIN CONFIDENTIAL** [redacted] **END CONDFIDENTIAL** of DEP customers' needs over that time period.

Duke's own analysis reveals that retiring its coal assets early would save ratepayers money. Once carbon costs are considered, Duke's "Earliest Practicable Coal Retirements" portfolio is often the cheapest option.[37] Even if carbon costs are *not* included, the "Earliest Practicable Coal Retirements" portfolio and Duke's Base Case portfolio are close in cost.

In addition to these costs, several of Duke's coal units are quite inefficient. Some units provide very little energy value.[38] Moreover, when some of Duke's coal units are operated during high demand periods, their output must be rapidly increased and then decreased. This requires Duke to burn significant amounts of fuel. In other instances, some of these units may serve as standby, backup generation.[39] These units may be operated and then connected to the grid for extended periods of time as they may require significant lead time to begin delivering energy. They are also likely to be deployed close to their minimum output levels, which is inconsistent with their originally intended design. As a result, these units burn coal at significant cost and produce significant emissions,

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CONFIDENTIAL [redacted] **END CONFIDENTIAL** and the load forecast from DEC IRP REPORT at 240, Table C-11.

[36] Strategen calculated this by using the capacity factors provided in response to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** and the load forecast from DEP IRP REPORT at 231, Table C-11.

[37] *See* DEC IRP REPORT at 189, Table A-16.

[38] Said another way, some of Duke's coal plants only supply a small number of kilowatt hours of electricity each year.

[39] Also referred to as spinning reserve. Spinning reserve specifically refers to power plants that (1) serve as excess generation and (2) can quickly provide supply in the event of power shortages.

even when they are primarily serving as a source of standby generation and it would otherwise be uneconomic to operate them. Duke's own modeling projects that its coal units will produce less than 40% of the capacity or maximum output they were designed to supply.[40] In fact, 13 of Duke's 17 coal units will provide less than 15% of capacity after 2025. For context, between 2015 and 2019, the average "capacity factor" for coal plants in the US ranged from 47.5% to 54.5%.[41]

3. Duke's Subjective Assumptions Inform Its Coal Retirement Analysis.

A standard, objective computer model would be the preferred method for selecting coal retirements. The model would calculate the amounts of generation required to ensure grid reliability while contemporaneously selecting coal or other resources for retirement. It is the approach that PacifiCorp[42] and many other utilities have adopted.

Duke however did not do this. Instead, it created a separate, four-step process to determine the economic retirement dates. Duke's approach does not appear to reflect the rigor of the IRP process. Instead, subjective decision-making appears to inform much of Duke's approach. Furthermore, Duke's approach does not appear to be based "on reasonable assumptions and best available current

[40] Based on Strategen's review of underlying data for DEC IRP REPORT at 79, Table 11A.
[41] Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, U.S. ENERGY INFORMATION ADMINISTRATION, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a (last visited Feb. 21, 2021).
[42] PACIFICORP, INTEGRATED RESOURCE PLAN, 2021 IRP PUBLIC INPUT MEETING, July 30-31, 2020 66 (2020), https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/07-30-31-2020_PacifiCorp_2021_IRP_PIM.pdf.

knowledge concerning implementation considerations and challenges."[43]

a. Duke did not use a computer model to economically retire coal.

Duke should have allowed its computer model or another model to economically retire coal. This approach would have been in accordance with standard resource planning principles. Instead, Duke first analyzed its coal assets in a separate study. It ranked each asset for retirement, and then compared the costs and "net production value" of each asset with a "peaker." In simple terms, Duke began by preliminarily assessing which coal units should be retired first. Duke then compared the costs and benefits of operating each coal unit with those of operating a natural gas plant designed to serve peak demand. All of this was done prior to Duke modeling the preferred or most optimal generation portfolio (optimal portfolio) to meet peak demand at least cost (portfolio optimization).

What this ultimately means is that Duke had already subjectively determined the most economic retirement date for each coal unit prior to portfolio optimization. In other words, instead of allowing the model to select retirement dates, Duke incorporated pre-determined retirement dates into the model.

Duke's model could have easily selected the most economic retirement dates on its own as it prepared an optimal portfolio. With those dates as a starting point, Duke could have then prepared a detailed and transparent action plan. If necessary, the plan could have delayed certain retirements on the basis of "implementation considerations and [real-world] challenges" not captured in the

[43] 2019 IRP Order at 8.

model.[44] Moreover, if Duke's System Optimizer model could not modify ongoing costs in real time, Duke could have used another model with that capability.[45] Duke has failed to compellingly demonstrate that its four-step process reflects the rigor of the IRP process or represents "the best available current knowledge concerning implementation considerations and [real world] challenges."[46]

b. Duke's grouping of large coal units appears to delay retirements.

Duke's initial priority ranking for retiring its coal units is the foundation of its four-step process. However, in preparing these rankings, Duke made a series of assumptions that may have distorted the retirement results. First, Duke's preliminary ranking includes several arbitrary coal unit groupings. For example, all four Marshall units are grouped together, despite having significantly different operating characteristics and projected capacity factors. Similarly, Belews Creek units 1 and 2 are grouped together. However, the four units at Roxboro are split into two groups: (i) Roxboro 1 and 2 and (ii) Roxboro 3 and 4. All the other remaining coal units are evaluated and ranked individually.

Second, Duke included ranking criteria such as the combined output of each assigned coal unit grouping. One might reasonably assume that larger groupings should be retired early because of their size and cost to ratepayers. However, Duke's ranking method assigns these larger, higher-cost groupings a lower priority for early retirement. These arbitrary groupings, along with Duke's assumption that larger groupings should be retired later, could have distorted the

[44] 2019 IRP Order at 8.
[45] *See* response to AGO DR 1-2(c).
[46] 2019 IRP Order at 8.

order of retirements.

c. Duke provides insufficient cost estimates to justify delaying certain coal plant retirements.

Duke has indicated that at least two of its coal plants provide "support to the transmission system"[47] and thus cannot be retired without additional transmission upgrades. In particular, Duke has determined that **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** of transmission upgrades respectively and has factored these costs in as a retirement constraint.[48] However, Duke's initial justification for these costs was inadequate. Duke initially stated that these costs were required because these plants provide **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** However, it is unclear how this could be given that **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** Additionally, it is unlikely these plants would be relied upon for **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** at the time of retirement due to their **BEGIN CONFIDENTIAL** [redacted]

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[47] DEC IRP REPORT at 80.
[48] *See* response to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**
[49] *See* response to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**
[50] **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

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Duke has provided additional, follow up information regarding these transmission upgrades. On first glance however, there still appear to be some issues with Duke's figures and justifications.[53] Given that this information was provided days before the filing deadline, the AGO reserves the right to provide additional comments on these transmission upgrades. Additional analysis is critical given the potential impact these costs had on the selected retirement dates.[54]

4. The Commission Should Reject Duke's Coal Retirement Analysis and Require a Better Model.

The Commission should reject Duke's coal retirement analysis and require Duke to include economic coal retirements in the same model runs used to select resources for its IRP portfolios. In addition, if there are practical constraints such as transmission upgrades or replacement generation that must be accounted for

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[52] Strategen estimates that the **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

[53] Strategen's concerns include, but are not limited to, the following: **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

[54] The fact that the upgrade costs could have a significant impact on the retirement dates is demonstrated by **BEGIN CONFIDENTIAL** [redacted], **END CONFIDENTIAL** according to Strategen's analysis. *See* Strategen Memo at 7, n. 31.

when determining retirement dates, or other reasons why Duke asserts that the earliest practicable retirement date is later than the economic retirement date, Duke should prepare a detailed and transparent assessment explaining why implementation considerations and [real-world] challenges warranted those delays.[55] At bottom, Duke's coal retirement analysis does not appear to be policy neutral. Instead, Duke made assumptions and policy choices that appear to have delayed coal retirements. There is no better example of this than Duke's failure to let its model economically retire coal. In addition, Duke's modeling may undervalue renewable energy, as discussed below, which could make coal plants even more uneconomic. In short, Duke's adopted approach deviates from standard planning protocols.[56]

This deviation could have significant, practical consequences outside of the IRP. The North Carolina Greenhouse Gas Inventory report indicates that electricity generation was "the primary GHG emissions sector in North Carolina" between 1990 and 2017, producing roughly 35% of the state's greenhouse gas emissions.[57] Coal in particular produced 73% of the state's greenhouse gas emissions from power generation, despite only producing 47% of the state's net, fossil fuel generation.[58] Given the risks climate change pose to the State,[59] identifying early

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[55] 2019 IRP Order at 8.
[56] *See* Strategen Memo at 5-9.
[57] NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, NORTH CAROLINA GREENHOUSE GAS INVENTORY (1990-2030) 9 (2019), https://files.nc.gov/ncdeq/climate-change/ghg-inventory/GHG-Inventory-Report-FINAL.pdf.
[58] *Id.* at 17, 18.
[59] *See* NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, NORTH CAROLINA CLIMATE RISK ASSESSMENT AND RESILIENCE PLAN (2020), https://files.nc.gov/ncdeq/climate-change/resilience-plan/2020-Climate-Risk-

coal retirements is vitally important.[60] Using a computer model to economically retire coal could potentially accelerate unit retirements. Early coal retirement is a key piece in our State's battle to address climate change.

B. Duke Should Extensively Study the Benefits of Neighbor Assistance and Identify how to Promote It.

1. Duke's Proposed Reserve Margin Could Increase Costs and Delay Coal Unit Retirements.

Under Commission Rule R8-60(i)(3), a utility must "provide a calculation and analysis of its winter and summer peak reserve margins over the projected 15-year period."[61] Furthermore, to "the extent the margins produced in a given year differ from target reserve margins by plus or minus 3%, [a] utility shall explain the reasons for the difference."[62]

The reserve margin represents the level of generation that is needed over and above what is required for peak demand, in order to ensure reliability. Duke projects higher energy demand in the winter.[63] Thus, its reserve margin is essentially the amount of excess generation it needs on extremely cold winter mornings. Heating and other end uses draw significant energy from the grid during the winter morning hours. Duke's 17% reserve margin would require it to either

Assessment-and-Resilience-Plan.pdf (detailing how climate change will impact the State's sea levels, increase summer heat, intensify hurricanes, and increase the risk of inland flooding).

[60] Natural gas plants pose many of the same climate risks and could burden consumers with high costs in the future.

[61] NCUC Rule R8-60(i)(3).

[62] *Id.*

[63] Utilities like Duke that have a higher peak demand in the winter than in other seasons are sometimes referred to as "winter peaking systems."

build or procure 17% more generation capacity than its projected winter peak demand.[64]

Pursuant to R8-60(i)(3), Duke has published resource adequacy studies which propose a 17% reserve margin.[65] These studies will have significant consequences for North Carolina ratepayers given the potential capacity costs.

To further illustrate this point, assume that Duke has a combined peak demand of 32,000 MW. A 1% reserve margin would then require Duke to have or procure about 320 MW of excess generation capacity. By extension, a 2% reserve margin would require 640 MW of excess generation capacity, and so on. Typically, Duke and other utilities use gas peakers for reserve margin as these resources are assumed to be more reliable than renewables. (As discussed below and in the comments of other stakeholders, these assumptions likely need to be updated). Duke's estimates indicate that a new gas peaker would cost approximately $75/kw-year.[66] Based on this $75/kw-year cost estimate, Strategen calculates that an additional 1% of reserve margin would translate to $24 million of levelized costs[67] for ratepayers each year. Conversely, decreasing the reserve margin by 1% would save ratepayers $24 million each year, with the added benefit of reducing fossil fuel emissions.

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[64] *See infra* III.B.1 for an illustrative example.
[65] By comparison, the neighboring PJM Interconnection has a 15% reserve margin. NERC, 2020 LONG-TERM RELIABILITY ASSESSMENT, DECEMBER 2020 107 (2020), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.
[66] See DEC IRP REPORT at 333. Assumes a 0% capacity factor.
[67] Strategen calculated this by dividing the peaker's lifetime energy production costs by the amount of energy the peaker produces.

There is also the possibility that a lower reserve margin could save ratepayers money by accelerating coal unit retirements. For example, DEC's IRP[68] indicates that it has sufficient capacity to both retire the Allen coal units and meet its proposed 17% winter reserve margin. However, Duke has determined that other coal unit retirements would result in it failing to meet its 17% reserve margin. Hence, replacement generation would be required for those coal units. However, if the reserve margin were less than 17%, it might be possible to retire additional coal assets without replacement generation. The determination of the proper reserve margin could potentially shift the economic calculus in favor of retiring coal units earlier.

Given these significant costs, it is critical that the Commission carefully examine Duke's resource adequacy studies by (1) reviewing the validity of Duke's proposed 17% reserve margin and (2) assessing what steps Duke could take to reduce capacity that exceeds system needs. Relevant to that inquiry, at least two aspects of Duke's resource adequacy studies merit further attention.

2. Duke's Resource Adequacy Studies Do Not Adequately Investigate How Neighbor Assistance Can Reduce Reserve Margin and Capacity Costs.

a. Duke Should Further Examine the Potential Benefits of Neighbor Assistance.

Duke's resource adequacy studies do not adequately investigate how neighbor assistance might impact the reserve margin and capacity costs. While Duke has conducted useful testing on the ties between utilities, it has neglected to pursue a number of promising solutions.

[68] See DEC IRP REPORT at 81.

For example, Duke tested an "Island Scenario" in which DEC and DEP were each required to maintain resource adequacy[69] without relying on each other or on neighboring systems providing neighbor assistance. The results showed that DEC would need a 22.5% reserve margin, 6.5% higher than the Base Case margin[70] that assumes moderate neighbor assistance.[71] Similarly, DEP would need a 25.5% reserve margin, 6.25% higher than the Base Case margin that assumes moderate neighbor assistance.[72] Accordingly, reliance on neighboring systems saves DEC ratepayers $156 million each year and saves DEP ratepayers $150 million each year.[73]

While it was appropriate for Duke to model and account for some of the benefits of neighbor assistance, Duke could have gone further. For example, Duke provides some estimates of what it would cost to install upgrades to increase neighbor assistance through its transmission infrastructure (transmission imports or imports).[74] The implication here is that these upgrades are too expensive and not worth pursuing. However, Duke fails to examine how the benefits of increased imports might make even an expensive upgrade worth the investment.

Strategen proposes that one option for assessing the benefits of increased neighbor assistance would be to test a relaxed import constraints sensitivity.[75]

[69] Sufficient resources to ensure required levels of reliability.
[70] *I.e.* reserve margin.
[71] *See* KEVIN CARDEN ET AL., ASTRAPE CONSULTING, DUKE ENERGY CAROLINAS 2020 RESOURCE ADEQUACY STUDY 8 (2020).
[72] *See* KEVIN CARDEN ET AL., ASTRAPE CONSULTING, DUKE ENERGY PROGRESS, 2020 RESOURCE ADEQUACY STUDY 8 (2020).
[73] Again, this assumes that levelized capacity costs decrease $24 million each time the reserve margin is reduced by 1%.
[74] *See, e.g.*, DEC IRP REPORT at 58.
[75] Strategen Memo at 11-12.

Currently, Duke's modeling assumes a ceiling on the level of imports. Presumably, this assumption is grounded in limitations in Duke's existing transmission infrastructure or operational protocols that have the effect of limiting imports. This sensitivity would therefore require Duke to evaluate how removing these limitations might impact the reserve margin. Strategen believes that removing constraints on PJM imports might be beneficial for meeting peak demand during the *winter* hours.[76] The North American Electric Reliability Corporation (NERC) projects that PJM's *actual* reserve margin will be approximately 40% over the coming decade, even though its market reserve margin *requirement* is only 15%.[77] As such, some of PJM's resources could be used to help Duke achieve resource adequacy. However, these import constraints would need to be addressed first.

b. Duke Has Not Sufficiently Explored Options for Increasing Neighbor Assistance.

If further analysis shows that increased neighbor assistance would support a lower reserve margin, Duke should then identify *how* best to increase neighbor assistance. Unfortunately, Duke's resource adequacy studies fall short in this regard. Furthermore, Duke has no planned transmission upgrade projects to support sharing outside of DEC and DEP.

Nevertheless, Duke might be able to unlock additional neighbor assistance with fairly limited interventions. For example, Duke could utilize dynamic line rating

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[76] *Id.* at 11-12.

[77] NORTH AMERICAN RELIABILITY CORPORATION, 2020 LONG-TERM RELIABILITY ASSESSMENT, DECEMBER 2020 107 (2020), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020_Errata.pdf.

technologies[78] to facilitate more imports with its existing infrastructure. Among other things, those technologies would allow Duke to monitor real-time transmission conditions and increase transmission voltage where possible. Furthermore, Duke could also upgrade some of its transformers to increase the level of imports. However, until Duke provides more information on its existing import limits,[79] it is unclear what specific interventions could potentially provide value.

3. The Commission Should Direct Duke to Re-Examine the Benefits of Neighbor Assistance and Identify Solutions If Revised Studies Support a Lower Reserve Margin.

Duke should be directed to conduct an additional analysis on the benefits of neighbor assistance and, if this analysis supports a lower reserve margin, Duke should then identify strategies for increasing neighbor assistance.

Resource adequacy is extremely important. The recent rolling blackouts in the California Independent System Operator (CAISO)[80] and Electric Reliability Council of Texas (ERCOT)[81] markets are a reminder that resource adequacy can be a matter of life and death.

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[78] US DEPARTMENT OF ENERGY, DYNAMIC LINE RATING, REPORT TO CONGRESS, JUNE 2019 (2019), https://www.energy.gov/sites/prod/files/2019/08/f66/Congressional_DLR_Report_June2019_final_508_0.pdf.

[79] Strategen Memo at 12-13.

[80] *See* Debra Kahn & Colby Bermel, *California has first rolling blackouts in 19 years – and everyone faces blames*, POLITICO (Aug. 18, 2020), https://www.politico.com/states/california/story/2020/08/18/california-has-first-rolling-blackouts-in-19-years-and-everyone-faces-blame-1309757. *See also* Alex Gilbert & Morgan Bazilian, *California power outages underscore challenge of maintaining reliability during climate change, the energy transition*, UTILITY DIVE (Aug. 19, 2020), https://www.utilitydive.com/news/california-power-outages-underscore-challenge-of-maintaining-reliability-du/583727/.

[81] Mitchell Ferman et al. *2 million Texas households without power as massive winter*

While the precise root causes of these blackouts are still being investigated, it is clear that increased neighbor assistance, along with demand side management and carefully integrated renewable energy and storage, must be part of the solution going forward.[82] Indeed, early evidence suggests that inadequate weatherization of natural gas plants, wellheads, and pipelines was more to blame for the Texas blackouts than solar or wind underperformance.[83] In a joint letter to Governor Gavin Newsom of California, state regulators made clear that "[r]enewable energy did not cause the rotating outages."[84] To suggest, as some have done, that renewables were to blame for these blackouts would require ignoring this evidence. Indeed, some of the core assumptions underlying whether certain clean energy resources can serve peak demand should be revisited. For example, solar can provide significant value when paired with storage.[85] Newer solar technologies may provide additional value and deserve to

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storm drives demand for electricity, THE TEXAS TRIBUNE (Feb. 15, 2021), https://www.texastribune.org/2021/02/15/rolling-blackouts-texas/. *See also* Dionne Searcey, *No, Wind Farms Aren't the Main Cause of the Texas Blackouts*, NY TIMES (Feb. 17, 2021) https://www.nytimes.com/2021/02/17/climate/texas-blackouts-disinformation.html.

[82] *See* Searcey, *supra* note 80 (noting that the "bulk of the power loss in Texas came from natural gas suppliers"). *See also* CAISO, FINAL ROOT CAUSE ANALYSIS, MID-AUGUST 2020 EXTREME HEAT WAVE 47-48 (2021), http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf (detailing the "1,000 MW difference between shown [natural gas] RA requirements and bid from [natural gas] RA resources" and concluding this difference was due to "forced outages and derates due, at least in part, to extreme heat").

[83] *See* Searcey, *supra* note 80.

[84] Letter from Marybel Batjer, the California Public Utilities Commission, Stephen Berberich, California Independent System Operator, and the California Energy Commission to California Governor Gavin Newsom (Aug. 19, 2020) (https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/Joint%20Response%20to%20Governor%20Newsom%20Letter%20August192020.pdf).

[85] *See generally* CHARLIE BLOCH ET AL., ROCKY MOUNTAIN INSTITUTE, BREAKTHROUGH

be thoroughly modeled. The AGO will continue to monitor developments from Texas and explore how the lessons learned there may be applied in North Carolina.

C. Duke Should Revisit its Clean Energy Assumptions.

1. Duke Should Consider Including 2-Hour Energy Storage as a Resource Option.

As part of the 2020 IRPs, Duke commissioned a study on the effective load carrying capability (ELCC or carrying capability) value of energy storage resources. Carrying capability is a critical IRP input that helps determine how much solar and storage can be relied upon to meet peak demand.[86]

The carrying capability study reveals that many storage durations provide comparable capacity values to those of firm capacity resources.[87] Specifically, capacity value attempts to measure how effectively a particular resource can address peak demand.

For example, DEP's study determined that the first 800 MW of 2-hour[88] storage provides at least 88% of the capacity value of an equivalent firm capacity resource like natural gas. [89] Although 2-hour storage has less capacity value than

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BATTERIES, POWERING THE ERA OF CLEAN ELECTRIFICATION 29 (2019) (on file with AGO) (establishing that certain, charged energy storage solutions can help utilities meet peak demand).

[86] Although the carrying capability study has value, Strategen believes the unforced capacity (UCAP) framework merits further attention and could allow for more accurate comparisons between renewables, storage, natural gas, and other traditional resources. *See* Strategen Memo at 14. Any analysis should subject natural gas resources to the same level of analysis as renewable energy resources, so that all resources are put on an equal footing.

[87] Refers to capacity resources that are guaranteed to be available and provide output.

[88] Assumes the recommended dispatch schedule.

[89] KEVIN CARDEN ET AL., ASTRAPE CONSULTING, DUKE ENERGY CAROLINAS AND DUKE

longer duration options, the converse is that it is much cheaper.[90] While Duke projects that the value of 2-hour storage will decrease with more additions, 2-hour storage remains a valuable resource up to moderate levels of penetration.[91]

Nevertheless, Duke has excluded 2-hour storage as an IRP resource option. Duke notes that "[a]s the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish, and for these reasons, DEC only considered four and six-hour battery storage in the IRP."[92] This explanation is not well founded for a few reasons. First, 2-hour storage is well suited to meet Duke's reliability needs, which are characterized by acute winter peaking conditions during the 7 to 9 morning hours in the month of January. Second, expanded winter DSM was not evaluated in the 2020 IRP base cases.[93] In light of these facts, the better approach would have been for Duke to include 2-hour storage as a resource option and then allow its computer model to select it where appropriate.

2. Duke Has Failed to Consider Potential Synergies between Winter DSM and Solar.

While Duke's carrying capability analysis is an important first step, Duke failed to consider potential synergies between certain resources. For example, Duke's modeling results[94] suggest that increased winter DSM can help address

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ENERGY PROGRESS STORAGE EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) STUDY 12, Table 5 (2020).

[90] U.S. ENERGY INFORMATION ADMINISTRATION, BATTERY STORAGE IN THE UNITED STATES: AN UPDATE ON MARKET TRENDS 17 (2020), https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

[91] Strategen Memo at 13-14.

[92] DEC IRP REPORT at 47.

[93] *Id.* at 36 (noting that it would have been premature to include the findings of the expanded winter DSM study in the base case); DUKE ENERGY PROGRESS, NORTH CAROLINA INTEGRATED RESOURCE PLAN 2020 47 (2020) (noting the same).

[94] Response to AGO DR 1-11.

winter peak demand. Specifically, winter DSM could shift some of the risk of outages from the winter to the summer. For context, winter outages typically occur during the early winter mornings, when the sun is barely out. In contrast, summer outages typically occur during the sunny daylight hours, when large numbers of residential households are forced to operate their air conditioning systems. This suggests that increased winter DSM may make solar more valuable, as it will produce more power during high demand periods. This in turn could reduce the risk of summer outages. Per Strategen's recommendation, Duke should reassess the capacity value for solar given its potential synergies with winter DSM.[95]

3. Duke Unreasonably Assumes Low, Annual Renewable Energy Interconnections.

The base cases in the 2020 IRPs assume what appear to be rather low amounts of annual solar and wind interconnections. These assumptions appear to be based on wind and solar's historic deployment rates. However, Duke has not provided sufficient justification as to why these rates would persist for the entire planning period. Indeed, given more recent developments[96] and Duke's growing interconnection experience, one could potentially expect higher rates of interconnection in the future. Duke's low modeled level of solar and wind interconnection may have hindered the consideration of these resources during the planning process.

[95] Duke should also explore potential synergies between solar and storage.

[96] *See* Order Approving Queue Reform In the Matter of Petition for Approval of Revisions to Generator Interconnection Standards issued October 15, 2020 in Docket No. E-100, Sub 101; Order Granting Petition for Limited Waivers In the Matter of Petition for Approval of Revisions to Generator Interconnection Standards issued October 14, 2020 in Docket No. E-100, Sub 101 (providing waiver relief to effectuate a settlement agreement that attempts to resolve significant backlogs in the interconnection queue).

4. The Commission Should Direct Duke to Revisit Its Clean Energy Assumptions and Re-Examine the Interplay between Winter DSM and Solar.

Therefore, Duke should include 2-hour storage as an IRP resource option, examine potential synergies between winter DSM and solar, and reconsider its wind and solar interconnection assumptions.[97] Furthermore, the Commission should consider the additional alternative resource recommendations set forth in Strategen's memorandum. As a whole, Duke's clean energy assumptions should be revisited. Duke's failure to reconsider these problematic assumptions and account for newer solar technologies like solar tracking systems[98] in its IRPs starkly contrasts with Duke Energy's embrace of green hydrogen and other more exotic technologies.[99] In addition, Duke's failure to consider the long-term costs of fossil fuel generation, such as the risk that natural gas generating plants will create "stranded" costs if natural gas plants, like coal plants, are required to close before the end of their expected lives due to climate legislation or policy.[100] In sum, these deficiencies suggest that Duke has failed to "consider and compare a comprehensive set of potential resource options, including both demand-side and

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[97] Additional issues regarding both alternative resource assumptions and insufficient substantiation are identified in Strategen's memorandum.

[98] Refers to panel systems that track the sun's trajectory. Duke should account for the fact that many solar facilities now use solar tracking systems.

[99] *See, e.g.*, DUKE ENERGY, ACHIEVING A NET ZERO CARBON FUTURE 25, 26 (2020) https://www.duke-energy.com/_/media/PDFs/our-company/Climate-Report-2020.pdf (indicating that Duke Energy projects 12% of its future generating capacity will be provided by new, "Zero Emitting Load Following Resources."). Green hydrogen and other emerging technologies should be put on an equal footing with all other forms of generation, including Duke's proposed expansion of natural gas generation. In addition, it should be subject to the same level of rigorous analysis.

[100] TYLER FITCH, ENERGY TRANSITION INSTITUTE, CARBON STRANDING: CLIMATE RISK AND STRANDED ASSETS IN DUKE'S INTEGRATED RESOURCE PLAN 48 (2021), https://energytransitions.org/carbon-stranding.

supply-side options" and "take into account, as applicable, system operations, environmental impacts, and other qualitative factors."[101]

IV. CONCLUSION.

The AGO respectfully recommends that the Commission require Duke to submit revised Plans that:

1) Use a simpler, more objective computer model that selects the most economic retirement dates for each coal unit at the same time it evaluates other resources. Duke could modify or delay the model's selected retirement dates to account for the time it takes to secure regulatory approvals or address other justifiable contingencies.
2) Re-examine the benefits of increased neighbor assistance. If increased neighbor assistance warrants a lower reserve margin, Duke should identify solutions that would enhance neighbor assistance.
3) Revisit the cost, value, and deployment assumptions that appear to constrain the integration of additional, alternative resources. Moreover, Duke should evaluate the interplay between winter DSM and solar.

Respectfully submitted, as corrected this the 4th day of May, 2021.

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[101] NCUC Rule R8-60(g).

CERTIFICATE OF SERVICE

The undersigned certifies that she has served a copy of the foregoing ATTORNEY GENERAL'S OFFICE CORRECTED INITIAL COMMENTS ON DUKE'S INTEGRATED RESOURCE PLANS upon the parties of record in this proceeding by email, this 4th day of May, 2021.

__/s/______________________
Margaret A. Force
Special Deputy Attorney General