New EPA Greenhouse Gas Emission Standards North Carolina Economic Impacts

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Introduction

In May 2023 the Environmental Protection Agency (EPA or the Agency) issued proposed emission standards (the Rules) for existing and new Fossil Fuel-Fired Electricity Generating units. Issued under EPA's Section 111 authority wherein the Agency asserts the right under the Clean Air Act and subsequent court rulings to regulate greenhouse gas emissions, the new standards, if sustained, would accelerate retirements of coal plants. The Rules also impact utility plans to operate existing and to build new natural gas plants.

The new EPA standards could impact Duke Energy's (Duke) Carbon Plan/Integrated Resource Plan (CPIRP, P-3 see Appendix 3), and by extension North Carolina's economy. Duke Energy's plan is required by NC House Bill 951, to reach an interim target of 70% carbon reduction and net-zero by 2050. Duke Energy's initial plan was submitted in May 2022 to the North Carolina Utilities Commission (NCUC). The NCUC then issued an order in December 2022, in which it approved Duke Energy's near-term action plan, and paid considerable attention to assuring that Duke's CPIRP did not adversely impact power costs for consumers or the reliability of supplies to customers. The Rules, if sustained, potentially supersede and hinder North Carolina's law and regulatory process. This in turn may cause major alterations of Duke's plans. Accordingly, the Kenan-Flagler Energy Center at the University of North Carolina has undertaken to study the changes Duke Energy would have to make to comply with the Rules and what such changes may mean for the North Carolina economy.

The topic is potentially vast. Its scope could encompass the entirety of how EPA's new standards competitively impact all 50 states. Rather than attempt something so complex, this White Paper focuses on four issues it can address in some detail:

1. **If the Rules are finalized as issued, how viable for NC are the solutions proposed by the EPA?**
2. **Given these findings, how would Duke Energy likely comply with the Rules? How would compliance alter the emissions reductions targeted by Duke under House Bill 951?**
3. **What would Duke's compliance plan mean for power reliability & cost in North Carolina?**
4. **How does Duke's compliance plan and ability to execute impact the NC economic outlook?**

In August 2023 Duke Energy submitted to the NCUC its CPIRP which included a sensitivity analysis for how it would comply with the Rules if they were finalized as proposed. We have since discussed this plan with Duke planning personnel, with the NC Public Staff, which operates as the NC consumer advocate, and with the EPA. While the latter conversation was circumscribed by the fact that the Rules are proposed and the EPA is still receiving comments, we were able to gain some insight into the Agency's expectations on compliance, its sensitivity to feasibility and cost issues, and its thinking behind the waiver procedures currently provided for in the Rules. Finally, the potential impact of these developments on North Carolina's economy was discussed with the state's Commerce Department and with subject area experts at the Kenan Institute for Public Policy.

There are many moving pieces to this picture. Even in the two months since this study commenced, Duke Energy's 'load' outlook (expectations of electricity demand) has changed markedly. This resulted in a supplemental filing to NCUC on January 31, 2024. The rapidly changing nature of NC's economic growth and electricity demand is seriously complicating energy resource planning and the ways and means of complying with EPA's proposed Rules.

Studying the Rules and their NC impacts thus presents a challenging mixture of dynamic elements (e.g., load outlook) and seemingly inflexible barriers (e.g., deadlines for plant retirement/operating modifications and obstacles to new infrastructure). A critical factor influencing the feasibility of the Rules will thus be whether these inflexible elements become more workable in the years ahead. Specific illustrations of this point will be made below, along with recommendations which would render compliance with the EPA's final Rules more feasible.

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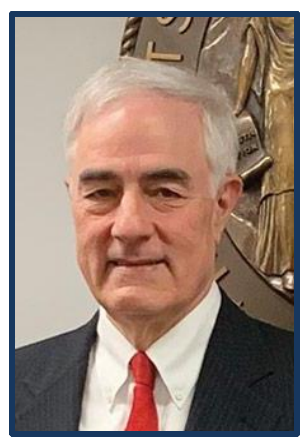

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Whitepaper: New EPA Greenhouse Gas Emission Standards

North Carolina Economic Impacts

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Executive Summary – 7 Key Points

1. The technical solutions contemplated by EPA's new Section 111 standards are impractical for the state of North Carolina. Their impracticality is less a matter of technological feasibility and more an issue of infrastructure barriers and bottlenecks. These are unlikely to be overcome in time to permit the state to meet the Rules' deadlines for shutting and/or altering operations at existing fossil fuel-fired generation facilities.

2. North Carolina is thus likely to comply with the Rules by operating new and existing gas-fired plants below 50% capacity factor and by building additional gas plants to make up for the foregone generation. Other than building more gas, Duke Energy's compliance alternatives are offshore wind, and perhaps advanced/small modular reactor nuclear power and pumped storage hydro. These are unlikely to be available in sufficient time and scale to materially alter a 'more gas-fired plants' outlook. This is especially the case in light of an increasing load outlook, one materially higher than the assumptions used in EPA's modelling. This increasing load outlook makes the timely addition of gas-fired capacity more essential as gas plants can run in baseload and ramp up/down quickly in conjunction with large, planned additions of intermittent renewables generation. If EPA can promote the removal of infrastructure barriers, these gas plants can later be converted to Carbon capture and sequestration "CCS" or H_2 co-firing use.

3. As a result, North Carolina's compliance plan will not result in fewer emissions than in currently approved plans and may result in higher emissions. Running gas plants inefficiently and building more gas plants to compensate is not a recipe for lower emissions.

4. Duke Energy will already be challenged by the risks inherent in executing the CPIRP selected by the North Carolina Utilities Commission. Rules compliance will require Duke to build an additional 2.5-4.5 GW of capacity on top of ~$ 30 billion "NC only" in planned CRIRP investments. This incremental capacity may include offshore wind and advanced nuclear. Duke has never built either form of generation. Rules compliance thus involves Duke increasing a record level of capital spending and taking on significant 'First of a Kind' risk. Thus, the Rules exacerbate Duke's execution risk, increasing the likelihood of overruns and delays.

5. The combination of high risk associated with the execution of Duke Energy's plan, inflexible EPA Rules deadlines for plant shutdowns/altered operations, and the fact that EPA's indicated enforcement discretion will only apply to emergency conditions, constitutes a serious threat to North Carolina's reputation for reliable power. Depending upon how EPA exercises its regulatory discretion, North Carolina may go from competitively advantaged to disadvantaged in terms of electricity reliability.

6. A Duke Energy CPIRP, if well executed, will continue to support the state's currently excellent 'place to do business' reputation. A difficult implementation will have the opposite effect. This is especially so given the role of tech/AI/data centers as major drivers of recent economic growth. Manufacturing, which has been moving to the state, also seeks reliable, affordable power. Should North Carolina suffer a notable series of unplanned power outages that are seen as resulting from Duke Energy's struggles to execute both its CPIRP and Rules compliance, further immigration of load-seeking investors would be discouraged. Existing customers may also exit as some tech/AI operations can readily migrate.

7. North Carolina's approved CPIRP could achieve emissions results equivalent to those sought by the Rules. Based on an assumption that it will, the state should submit its existing CPIRP as the State Plan required by the Rules and seek EPA's approval. If granted, this would avoid the application of the Rules to specific NC plants, reduce Duke Energy's execution risk and help insulate the state's economy from erosion of its reliable power reputation. This approach would also be consistent with EPA incorporating enhanced 'off ramps' for reliability issues into its final Rules.

Executive Summary – 5 Recommendations

1. ***EPA's definition of the 'Best System Emissions Reduction' (BSER) should take infrastructure barriers more into account*** when considering when such systems will be available at scale. EPA should indicate that to the extent permitting and other reforms needed to overcome such barriers do not materialize, it will be more inclined to grant states and operators flexibility under its enforcement discretion and State Plan review processes (see below).

2. ***'Blue' or other forms of Hydrogen that meet the low CO_2 emissions standard should be identified as acceptable for use to co-fire fossil fuel generation.*** Doing so would create a consistent approach with using carbon capture and sequestration as a means for de-carbonizing fossil fuel plants. It should not matter whether CCS is applied to de-carbonize a natural gas power plant or to de-carbonize production of the hydrogen that replaces natural gas in the power plant's turbine combustion. It would also signal the acceptability of 'pink hydrogen' tied to nuclear power. This approach to hydrogen production is already being incorporated into advanced reactor designs such as those being developed by TerraPower.

3. ***EPAs Rules process should contemplate operators anticipating reliability issues.*** Rather than granting relief only after an emergency arises, the EPA should adopt reliability mechanisms that enable ISO/RTOs and utilities to seek relief based on credible multi-year outlooks of inadequate power reserves and/or grid adequacy risks.

4. ***States whose approved plans will achieve emissions targets similar to or better than EPAs should be encouraged to seek State Plan approvals even if their means of achieving such targets are not based on the BSERs favored by EPA.*** State Plan approvals should also be considered if states can show that Rule compliance will result in more, not fewer emissions.

5. ***Small Modular (SMR) and Advanced Nuclear Reactors should be identified*** as options EPA will view favorably in exercising its discretion when reviewing State Plans. It is not clear whether EPA could legally classify nuclear technologies as a BSER. However, EPA can signal it will view nuclear favorably when reviewing State Plans that meet the Rules. Doing so will provide operators with more options. It may also encourage operators to accelerate the development of nuclear technologies. Such acceleration will complement the renewables and storage buildouts that the Rules are promoting by offering firm, dispatchable power to balance more intermittent generation. It will also hedge the possibility that operators end up building more natural gas plants due to a lack of feasible alternatives.

The Report - Principal Findings:

In this section, answers are provided to the four questions outlined in the Introduction, i.e.,

1. **If the Rules are finalized as issued, how viable for NC are the solutions proposed by the EPA?**
2. **In light of these findings, how would Duke Energy likely comply with the Rules? What changes would Duke Energy's compliance plan imply for targeted emissions reductions?**
3. **What would Duke's compliance plan mean for power reliability & cost in North Carolina?**
4. **How does Duke's compliance plan and ability to execute impact the NC economic outlook?**

We begin with the viability of EPA's recommended alternatives, CCS and hydrogen co-firing. These answers will be followed by Policy Implications and Recommendations.

Feasibility of EPA's Proposed Solutions for NC

Infrastructure bottlenecks mean the solutions contemplated in EPA's Rules are unrealistic for a state like North Carolina. The Rules intend to accelerate utility adoption of de-carbonized power generation. The principal solutions contemplated are carbon capture and sequestration and hydrogen co-firing (blends of H_2 with natural gas as combustion turbine fuel). CCS is logistically infeasible for NC. It is currently believed that the state's geology does not offer locations for secure underground storage. Captured carbon would thus have to be piped to a secure storage site, most likely the Gulf Coast but also possibly GA/PA/WVA. In the aftermath of environmental/legal challenges having killed the Atlantic Coast Pipeline and repeatedly delayed the Mountain Valley Pipeline, new interstate pipelines are seen to be of questionable feasibility. Private sector firms can neither predict when they could be completed nor what they ultimately will cost. This same consideration applies to hydrogen supplies. Only the U.S. Gulf Coast has the industrial infrastructure, the experience in manufacturing and in safely handling hydrogen, and the storage capacity for de-carbonized H_2 manufacturing at scale. Thus, for H_2 supplies to be available in the quantities required to co-fire an extensive natural gas plant fleet, it will be necessary to construct new hydrogen pipelines connecting NC to the Gulf Coast. As of today, no hydrogen pipeline network exists outside the U.S. Gulf Coast, and there are no serious plans underway to build one.

EPA's Rule deadlines also fail to consider the execution challenges of the changes they seek. The Rules begin to impact existing coal and natural gas plants in the 2030-32 timeframe. By then "Long-term" coal units must have CCS installed. Advanced Combined Cycle Natural Gas Plants (CCNG) must adopt CCS or partial H2 co-firing by 2032-35 or transition to operating below 50% capacity factor. [1] For NC, this involves retiring coal-fired units comprising more than 6 GW of capacity and transitioning to a similar sized NG fleet. [2] This natural gas-fired plant build-out is needed to complement the extensive new renewables/storage capacity called for in the CPIRP. For Duke to be ready by 2032-35 to either install CCS or adopt H2 co-firing at these gas plants, the planning of such CCS/H2 projects would have to begin immediately. Final Investment Decisions (FID) would then be made in the 2028-29 timeframe. To be able to make these FIDs, secure means of acquiring, shipping, and storing H2 + CCS would have to be available for contracting by 2027-28. This means the H2 and CCS suppliers/shippers would have had to secure their necessary permits and environmental approvals in 2025-26. Any reasonable review of recent permitting and infrastructure construction would lead to the conclusion that this is unlikely to occur.

Local purpose-built hydrogen manufacturing is also infeasible as a North Carolina solution. EPA indicates that Inflation Reduction Act (IRA) tax credits should be a major assist in enabling hydrogen manufacturing to get to scale. However, a combination of the U.S. Treasury's proposed regulations and North Carolina's circumstances render this unlikely. The IRS regulations indicated that tax credit eligibility depends on 1) only 'clean' power is used for electrolysis and 2) that said power must be surplus to the grid, i.e., not be taken away from existing customers. [3] These conditions are highly restrictive. They essentially mean that Duke cannot mix and match power from different sources to support a 24/7 hydrogen manufacturing process. Moreover, there is no 'surplus power' in Duke's plans. A rising load outlook means that all of Duke's record capital spend is dedicated to meeting expected demand. Thus, for North Carolina the IRA 45V hydrogen tax credit would require new purpose-built solar/wind/storage plus some unknown backstop to an electrolysis plant. Such an expensive solution is likely to render the IRA's 45 V tax credit's attractiveness moot.

EPA's rule will inevitably be challenged, and extended litigation will add to the uncertainty around whether it will be necessary to adopt EPA's proposed solutions. This will exacerbate the planning dilemmas associated with the Rules' 'hard deadlines' for plant closing/operating modifications. Do utilities start implementing a compliance plan now, only to discover it ultimately is not needed? Do they ignore the Rules only to discover that they are upheld and now it is too late to enact EPA's solutions? EPA's unrealistic deadlines will be challenged even further with the prospect of prolonged litigation of the Rules. Meanwhile, utilities like Duke Energy may find themselves in a planning 'limbo' with the clock ticking towards EPA's deadlines.

How would Duke Energy Comply with the Rules? Would Compliance alter the CPIRP targeted Results?

Given the infeasibility of CCS and H2 co-firing for Duke Energy, the utility likely would comply with the Rules by combining more natural gas generation with some offshore wind capacity. To comply with the Rules, Duke Energy foresees having to add ~2.5 GW of net generation capacity by 2035 (see Appendices 4 & 5). This figure reflects additions of new plant and deletions/deferrals of other base plan facilities but does not reflect Duke's latest (January 2024) projections of load growth. [4] Duke Energy sees its alternative zero-carbon compliance options as limited: more renewables, new nuclear or more operated <50% capacity natural gas. Duke Energy's CPIRP foresees adding a large amount, 12 GW of solar by 2035. As of 2019, Duke Energy's entire system had only 5 GW of solar, so Duke Energy's base solar target is ambitious. Duke Energy has one 600 MW SMR project by 2035 in its CPIRP. As discussed below, seeking to increase nuclear capacity will have at best a marginal impact on the capacity available for complying with EPA's Rules. Duke Energy thus sees offshore wind (1.6 GW) backed by more (2.2 GW) gas-fired plants as its best compliance options. [5] These replace some plan CPIRP projects, resulting in the net 2.5 GW additions to generation. Appendix 5 provides more details on Duke Energy's Compliance Plan.

Trying to accelerate new nuclear would have only a marginal impact on Duke Energy's Compliance Plan. The options for new nuclear consist of large (e.g., AP-1000, L-W) light-water reactors (1-2 GW), small modular reactors and/or advanced reactor designs. Recent large L-W reactors have taken 12 years to build and have cost 2-3X original budgets. Such projects are thus considered 'bet the company' propositions and are out of favor versus SMRs/advanced reactor designs. As of today, no SMRs or advanced reactors have been built in the U.S. Ontario Power is proceeding with a GE-Hitachi SMR, and TVA is considering one at Clinch River. These projects' capacities will be in the range of 300 MWs. It is unknown how long it will take for any utility to license and construct an SMR project. Even if that timeline were shortened to 7 years from the 14 Georgia Power took to build its Vogtle 3-unit, Duke Energy would be hard-pressed to get one 300 MW project finished by 2032, plus a 600 MW SMR by 2035. Measured against the projected 2.5 GW of needed generation, adding a 300 MW SMR to current plans represents only a marginal gain.

Further increasing gas-fired plant additions is the default option if offshore wind proves infeasible or too expensive. Duke Energy does not have experience building offshore wind. Inflation and supply chain challenges have also beset projects contracted by utilities in the northeast. The most comparable project here is Dominion Resources' Coastal Virginia Offshore Wind (CVOW) venture. Reported costs for

CVOW have risen 25% to $10 billion. Though that project appears able to start on schedule with power costs are projected to be in the range of $77-80 MWH. [6] Those costs compare to sub-$40 MWH for combined cycle natural gas (CCNG) and solar/onshore wind when they are producing. [7] Offshore wind projects elsewhere have been subject to cost escalations, infrastructure challenges to bringing power onshore, and NIMBY/environmental opposition. These uncertainties render NC offshore wind at best a compliance 'possibility.' An NCUC concerned with power costs and reliability may oppose such a project as too risky or too expensive. They could make this decision knowing that Duke Energy's gas default option offers more predictable timing and costs.

'Load' growth is adding to the uncertainties associated with Duke Energy's base/compliance plans. While Duke Energy has some history of over-forecasting electricity demand, it recently has been surprised by the large power increments demanded by tech companies, data centers and AI firms seeking to move into the state. [8] EPA's modelling, on which it based the Rules, assumes load growth of only 1.3 % p.a. [9] Duke Energy recently filed supplemental testimony projecting load growth of 2.5-3% p.a. [10] This growth, if it materializes, likely would require Duke Energy to build another 2 GW of natural gas-fired generation. North Carolina law imposes on Duke Energy an obligation to serve within its franchised service area. Faster than anticipated load growth will put even more pressure on Duke Energy's ability to maintain assured power supplies and power quality at the same time it is implementing its CPIRP and complying with the Rules.

Complying with EPA's new standards likely will not result in a reduction in GHG emissions and may lead to increased emissions. North Carolina's House Bill 951 and Duke Energy's CPIRP target a 70% CO_2 emissions reduction by 2035 (vs. 2005). [11] These targets are in line with, and in specific years better than, the EPA's Rule 111 goals. By forcing Duke Energy to operate gas plants at or below 50%, the Rules would compel the utility to build ~2+ GWs of additional gas-fired generation and possibly more if the offshore wind option fails to materialize. If CCS and H_2-cofiring are not realistic options, forcing Duke to operate existing gas plants inefficiently and build more gas-fired plants to compensate does not seem like a recipe for reducing emissions. In this way, applying the EPA's Rules in this state will likely result in no emissions reduction and may indeed cause an increase.

What would Duke Energy's Rules compliance plan mean for power reliability & cost in North Carolina?

The Rules pose a threat to the reliability of electricity supplies in North Carolina. Duke Energy will already be challenged to execute its CPIRP. That plan involves a $30+ billion capital spend (NC-only) between today and 2035 with the simultaneous shutdown of numerous operating units. [12] This spending estimate does not include the transmission projects required to connect the new generation within its service area and upgrade the grid. The Rules then present a major complication for this challenge. EPA's approach amounts to a 'bet' on alternative generation technologies, which either will be technically unproven, logistically infeasible, or excessively costly for NC. Moreover, the Rules impose 'hard deadlines' for existing plants to close or to modify their operations. This contrasts with the NCUC's approach, which favors frequent evaluations of progress and flexible deadlines for meeting emissions targets. The resulting combination: a base CPIRP requiring a record capital spend, EPA's bet on costly and risky solutions, and the Rules' superimposed hard deadlines, amounts to a serious increase in reliability risk for NC electricity supply.

EPA's proposed reliability mechanism is inadequate to address NC's power reliability risks. EPA proposes that utilities may request enforcement discretion based upon emergency conditions. [13] This means the emergency will already have had to occur. Presumably, a waiver would then allow natural gas-fired plants to operate at full capacity and/or coal-fired plants to be brought back into operation. It is questionable whether those measures will prove adequate to the situation. Will enough operating plants exist with spare capacity to respond? Will shut down plants even be available to come back online and if available within what period? Will any of this be adequate to address the magnitude of the winter storm, the hurricane, or the heat wave in question? EPA may feel that it is always a utility's responsibility to plan for reliable and resilient power supplies. This view, however, ignores the magnitude and complexity of the changes which the Rules will impose on utilities like Duke Energy and the cost of assuring generating capacity is in reserve to address an anticipated emergency demand. Coming on top of a massive capital spend, much higher load growth and numerous plant retirements, the Rules' waiver protocols don't offer utilities like Duke or ISO/RTOs the opportunity to see a crisis coming and ask in advance for relief.

EPA has publicly stated that it has 'tools' to ensure the Rules don't jeopardize reliability, but these tools don't offer utilities or state regulatory certainty or a reasonable planning environment. An EPA spokesperson has publicly touted 'State Planning Flexibilities' (SPFs) and Administrative Compliance Orders (ACO) as *"multiple tools at our disposal to ensure our rule…will not impair the ability of grid operators to ensure the reliability of the bulk power system."* [14] The former refers to states having a two-year planning window to work with power plant operators, identify potential contingencies and propose needed flexibility to EPA. The latter refers to EPA's enforcement protocols. If an operator fails to comply with an EPA rule, EPA may issue an ACO; such an order finds the operator to be legally non-compliant. Usually, EPA gives the operator some time in which to comply, after which it applies penalties. Civil parties, that is private individuals or organizations, may also sue either the operator or EPA if they believe proper enforcement of the law has not been achieved. These conditions mean that the availability of EPA discretion via ACOs is of little comfort to operators. ACOs enter the picture only after the operator is legally exposed via a violation. Even if the EPA offers flexibility, such can then be challenged or reversed by civil suits. Activist environmental organizations can be expected to file such suits should the EPA offer operators such flexibility. It will be difficult for operators to count on ACOs for reliability support if they must first violate the law, then count on EPA regulatory discretion, and then face the likelihood of and time involved in civil litigation.

As for the SPFs, these are welcome; this paper proposes an approach which could render SPFs a partial solution to the Rules' reliability risks. At present, they amount to a form of regulatory discretion where an applicant state has no assurance as to how much flexibility will be provided. This leaves states and operators having to plan for the possibility that flexibility is not forthcoming. Should that be the case, states and operators would again find themselves non-compliant, subject to an ACO and exposed to civil suits. At a minimum, the EPA must provide clear ground rules under which favorable treatment of SPFs can be expected.

Duke Energy likely underestimates the impact on power costs of its base CPIRP. Duke Energy projects that its base plan will increase monthly residential bills from \$125-\$175 per 1000 KWHs by 2035. [15] This amounts to a 2.5% CAGR, roughly in line with projected inflation. Limiting residential power costs to such increases would be an achievement. As noted, however, these projections exclude transmission/distribution additions and upgrades. Moreover, these projections likely underestimate the potential for cost overruns. To give some examples, Duke Energy's base plans include almost \$4 billion for onshore wind and \$5.5 billion for advanced nuclear. [16] Little onshore wind and no advanced nuclear has been built in NC to date, and in the case of advanced nuclear, none has been built in this country. 'First-of-a-kind' plants commonly cost much more than budgeted (see the Dominion CVOW project discussion above). Cost overrun risk is also inherent in the sheer size of the capital spend Duke Energy is attempting, the number of projects under development simultaneously, and the supply chain challenges arising from the Rules forcing other utilities to pursue similar spending programs.

Duke Energy likely underestimates the impact on power costs of its EPA Compliance Plan.

As noted, to comply with the Rules, Duke Energy projects are building additional natural gas-fired combined cycle and combustion turbine plants, plus offshore wind. Duke Energy is facing constraints on gas supplies in its base plan, and adding gas-fired capacity raises issues of both fuel cost and availability. Offshore wind is problematic from a cost perspective, given the experience encountered to date by developers and utilities like Dominion. Numerous project cancellations now characterize the offshore wind industry, as developers confront contractor cost escalations, higher financing costs, and challenges in obtaining rights to bring power 'onshore.'

To contain Residential Power Rates, NC will likely charge 'large load' users rates reflective of their unique costs of service. An influx of IT, Tech, AI and Data Center customers lies behind Duke Energy's recent projections of significantly higher power 'loads.' Individual users of this type can demand 300-500 MWs just for their facilities. Even higher single-customer load requirements may be coming. While these customers care about power costs, they are seen to be more concerned that power is reliable and high quality. Meanwhile, the process by which rates are set in NC seeks to protect retail customers from subsidizing such a large load of customers. Moreover, while Duke Energy welcomes these load additions, NC's current executive government branch is less enthusiastic. Such firms are not seen to be large-scale employers; the state's Commerce Department representatives thus are more interested in new manufacturing facilities, such as EV battery plants. These representatives also caution that potential new companies with objectives for greenhouse gas reductions might go elsewhere unless state policies are consistent with their objectives. [17] Together these conditions imply that the state likely will adopt rates requiring 'large load' customers to pay up for power. [18] Adoption of such a pricing policy must be added to emerging concerns about reliability when considering whether 'large load' customers continue to move into NC and whether existing customers 'stay put.'

How does Duke Energy's compliance plan impact the NC economic outlook?

A difficult execution of its de-carbonization efforts, one marked by repeat outages, could 'de-rate' the state's favorable current reputation for power reliability. The EPA Rules, if finalized as issued, materially increase the risk of a less-than-optimal execution by Duke Energy. Poor execution here reflects the challenges inherent in Duke's CPIRP compounded by the hard Rules and deadlines. Together they require a massive buildout in renewables with all the attendant challenges of securing land, getting through the queue, establishing grid connections, and backfilling their intermittency while a large amount of dispatchable power is retired. It also involves the risk of delays and overruns for a record level of capital spending while simultaneously retiring the coal fleet. NCUC saw all this risk and adopted a cautious approach. EPA's Rules say NC must do it all by a date certain. It is that collision, state flexibility superseded by hard EPA deadlines, that raises the execution risks of what is already a most ambitious net zero program.

North Carolina's economy has been robust, generating above-average growth. As a place to do business, NC was rated #1 in 2023 by CNBC (see Appendix 6). 19 The State ranked #1 overall in terms of Workforce, #3 in terms of Economy and # 6 in terms of Tech/innovation. 20 According to data from *Rich States, Poor States*, North Carolina ranked 2nd in the United States for its economic outlook and 10th for its economic performance. More specifically, between 2011 and 2021, North Carolina experienced a cumulative GDP growth of 53.37%, ranking 12th nationally. 21 In terms of cumulative domestic migration during 2012-2021, the state ranked 4th with a total of 600,579 people moving to North Carolina. Additionally, the state saw non-farm employment growth of 18% between 2011 and 2021, placing it 11th in the nation . These rankings and data suggest not just robust economic growth, but that an attractive economic environment brought both people and investment into North Carolina during this period.

An influx of tech, AI and data center firms has been a major driver of recent NC economic growth. As regards tech as a major driver, NC now ranks 4^{th} in the nation in tech-related jobs, with the sector accounting for 20% of the state's economy and 24% of payrolls. Over 80% of in-state tech CEOs foresee an ongoing need for additional tech workers. 22 This tech influx has contributed large increments of electricity load demand, i.e., 300+ MW per new tech project. Amazon, Meta and Google now operate data centers in central NC.

The state's reputation for affordable and reliable power supplies has been an important factor in luring these firms to immigrate to NC. However, that reliability reputation is now somewhat at risk. Duke Energy's average residential power price is about 5% below the national average while its average electricity price of $0.13/kWh is significantly lower than the national average. 23 Before 2022 North Carolina enjoyed a positive power reliability reputation. That was impacted by significant weather-related outages in December 2022. This subsequently resulted in North Carolina being ranked as having the fourth worst number of recent power outages, exceeded only by California, Michigan and Texas. 24 This result is a warning that North Carolina's reliability reputation is at risk.

Duke Energy's CPIRP and Compliance Plans will thus have major implications, positive and negative, for NC growth. The outcome will be a function of the size and challenge of what Duke Energy must implement and how well Duke Energy executes. The Rules add both size and complexity to what Duke Energy must accomplish. Concerning NC's economic outlook Duke Energy's plans involve many 'moving pieces:' shutting power plants, spending on replacement and growth-serving capacity, and introducing new options such as offshore wind and SMRs. The effects of all such activity on power costs and reliability can cut in several directions. Higher power costs could depress growth, although NC may still compare favorably relative to other states. A successful plan execution could burnish the state's economic reputation with additional clean power credentials. However, more frequent outages and power quality issues would be a real concern, one that discourages investment in both manufacturing and the tech sector. What outlook comes to pass is TBD. However, having to implement Rules' compliance on top of Duke Energy's base CPIRP while operating more plants below capacity when the load is surging - will be very challenging.

Looking at specific components, the negative local economic impacts of power plant shutdowns will be largely offset by site redevelopment. Retiring coal plants does pose a material loss of jobs for the immediate area. Coal plants require an extensive workforce to handle everything from coal deliveries and inventory management to operating the turbines, maintaining a complex plant and dealing with environmental concerns like coal ash disposal. These jobs will disappear when the coal plant is retired. However, the coal plant sites remain useful in many ways. They offer existing connectivity to the grid, site permits and approvals that can be extended/repurposed, and some existing infrastructure to be reused. Duke Energy plans to re-purpose all nine sites where coal generation will be retired. Most will become gas plants, and one or more may host new nuclear. The workforces for these plants will be different and, in some cases, smaller. However, much of the local economic impacts from coal plant shutdowns will be offset by new construction and ongoing operation of new generation.

From the state's perspective, any net coal plant retirement losses are more than offset by the massive renewables and gas plant buildout envisioned in Duke Energy's CPIRP. As noted, the jobs will be different, and some will be in different locations. However, the investment activity will surpass what Duke Energy undertook in any previous decade. Duke Energy Carolina's (NC & SC) capital plan foresees spending $52 billion over the next ten years. [25] This spending will inject a constant stream of stimulus into activities as diverse as engineering, procurement, supply chain and construction. Some of this can be seen in the growth of Duke Energy's use of contractors. Each new combined cycle natural gas plant will require extensive use of contractor support, peaking at 800 for each plant. [26] Additional resources will be required at Duke's HQ, as most of the activity will unfold within NC.

How NC's economy will fare competitively will also be influenced by how other states adopt plans to implement the Rules and whether EPA approves those plans. Without question, power rates will go up in NC, and probably by more than Duke Energy projects. How NC's power supplies will then compare with costs in other states will vary with the options other states deploy, the extent of their compliance, and how EPA exercises its discretion to approve state plans. There are uncertainties here, rooted in the different structures of power markets and how various utilities decide 'to play the game.'

Utilities in traditionally regulated states with a legal 'obligation to serve' may feel compelled to begin implementing Rules' compliance plans. Those operating in competitive/merchant markets may choose to rely on filing legal challenges or at least await the outcome of challenges anticipated to be made. Analysts and pundits predict that the U.S. Supreme Court will curtail or eliminate the 1984 Chevron deference doctrine in recently argued cases of *Loper Bright Enterprises v. Raimondo* (S. Ct. 22-451) and *Relentless, Inc. v. Department of Commerce* (S. Ct. 22-1219). If so, challenges to EPA's reliance on any ambiguities in the Clean Air Act to support the Agency's final Rules can be anticipated. Depending on whether the Rules do/do not 'stick,' traditionally regulated utilities could alternately find themselves 'ahead of the game' or having spent time, money, and effort on projects they didn't need to implement. Meanwhile, competitive power market producers could find themselves either well-positioned with their status quo plans or in catch-up mode.

Here it should be noted that competitive market ISO/RTOs expressed the strongest concerns about reliability in comments to EPA, questioning the Rules' contribution to lower emissions. As summarized by consultancy Scott Madden, those comments were:

"System operators had significant concerns about the effect of the rule, fearing that if the technology and infrastructure failed to timely materialize, then forced retirements of coal and even efficient gas-fired generation would leave the future supply of dispatchable generation below what is needed to serve demand, potentially resulting in "material, adverse impacts" to reliability."

ISO-New England pointed out in its comments that the capacity factor thresholds will incentivize less efficient operations of the natural gas fleet and will also reduce production by gas units nearing the 50% threshold that may be needed for system reliability. ISO-New England's simulations found that fossil generation would not decrease, but it would shift from larger, efficient gas-fired turbines to smaller, less efficient oil- and gas-fired units." [27]

While far from certain, the most likely outcome is that North Carolina retains some relative 'power cost advantage' within a broader context where nationwide power supplies become more expensive. Given Duke Energy's large existing nuclear power and efficient natural gas-fired fleets, it is difficult to see the state ending up 'disadvantaged' on power costs. However, pure cost has not been the state's only competitive edge in power. That edge also has been reliability, where until December 2022, Duke Energy had never had to implement any rolling blackouts. 2022's interruptions were short-term and resulted from factors that were difficult to anticipate. To the extent that future performance positions the 2022 outage as a minor exception, NC should continue to enjoy an important competitive edge from reliability. Will that be the case?

The Rule's biggest threat to North Carolina's economy thus lies less in its impact on power prices and more in its potential for damaging the state's reputation for reliable, resilient power supplies. As noted, very reliable power supplies available to service large demand increments have been a key driver of North Carolina's economic growth. As also noted, this reputation has lately suffered some erosion. The most dangerous reliability scenario for Duke Energy and NC is thus the following: the Rules 'stick,' Duke Energy implements an increasingly complex CPIRP + compliance plan with serious execution risks while other states/utilities that can't/won't comply, and instead pursue court challenges. If then, the final Rules are altered or overturned in the courts, but Duke Energy is locked into suboptimal plans implemented with large overruns and time delays, North Carolina will be seen as offering less predictable and secure power supplies. This in turn would erode the state's investment climate and competitive position relative to its position today. If the deterioration is bad enough, it could even lead to the exit of tech firms and data centers that recently moved to the state.

Policy Implications and Recommendations

Valid criticisms that the Rules are counting on technologies that are not and will not be available at scale could be overcome by reforms involving limited cost or environmental concessions. These reforms amount to re-permitting activities which were allowed not long ago, applying consistent principles across the slate of de-carbonization options, and/or peeling away accretions of regulatory/legal barriers that jeopardize project schedules and costs. These include:

Infrastructure barriers: These are a major, if not the greatest, obstacle to realizing the 'Best System Emissions Reduction' (BSER) applications essential to complying with the Rules. Permitting reform to enable CO_2 and H_2 pipelines to be constructed on predictable schedules at projected costs must be enacted to allow BSER applications to reach scale at an affordable cost.

"Blue and Other Color Hydrogen:" H_2 made from natural gas with CCS to capture the CO_2 or such other hydrogen supply that meets the Rules standards should be an acceptable source of hydrogen for co-firing. If CCS is acceptable for de-carbonizing natural gas-fired power plants, it should be an acceptable means for accomplishing the same outcome at hydrogen plants. The same should apply to other forms of hydrogen manufactured from low-carbon power, such as hydrogen produced using nuclear generation.

EPA's procedures for reliability assurance mechanism: These should be modified to allow ISO/RTOs or utilities to petition for implementation of reliability assurance mechanisms based upon credible multi-year outlooks of inadequate reserve capacity and/or grid flexibility. EPA can define the outlook period in question.

Federal/State regulatory engagement: These are an issue in play with the Rules, i.e., as in NC, various utilities may already have advanced low-carbon power plans through state legal/regulatory reviews. Such states and/or state commissions should be allowed to seek EPA 'State Planning Flexibility' approvals based upon the state's plan targeting an emissions reduction comparable to that being sought by the Rules. EPA should make clear that it will view favorably a State Plan that broadly meets EPA's emissions targets even if it doesn't encompass the specific BSERs contemplated by the Rules. Moreover, the EPA should be prepared to accept a State Plan that fails to meet EPA targets if the state can credibly show that strict compliance with the Rules' BSERs would lead to more, not fewer emissions.

Nuclear power: New nuclear will serve EPA's emissions goals while enabling utilities to meet load growth and manage renewables intermittency. New nuclear and existing plant life extensions should be explicitly contemplated as means to achieve compliance, and State Plans relying on such projects should be viewed favorably. Special challenges face those utilities considering the first SMR/advanced reactor projects. They face the risks associated with unproven designs and undeveloped supply chains. Thus, while IRA subsidies are available for next-gen reactors, one-time additional subsidies should be provided for the 'First of a Kind' (FOAK) nuclear projects. Efforts should also be made to ensure that the new NRC licensing regime for SMRs/advanced reactors in practice shortens the historic 10–12-year period it takes to license and start such facilities. Streamlined licensing and commissioning should especially be allowed when existing plant locations are being repurposed, e.g., from coal plant sites to nuclear.

Appendix 1

A Summary: EPA's New Source Performance Standards for Greenhouse Gas Emissions from New, Modified and Reconstructed Fossil Fuel-Fired Electric Generating Units

On May 11, 2023, the U.S. Environmental Protection Agency (EPA) proposed new CO2 emissions standards (the Rules) for fossil fuel-fired power plants. EPA issued these standards under Rule 111 of the Clean Air Act. This Act and subsequent court rulings have enabled the agency to assert the authority to develop and enforce standards for new and existing sources of air pollution. Thus, the EPA believes it can set limits on the amount of air pollution that power plants may emit into the atmosphere and require such plants to adopt the 'Best System Emissions Reduction' (BSER) technology to observe such limits. CO2 has been defined as an air pollutant subject to EPA regulation, a position upheld in several court decisions including the Supreme Court's decision in Massachusetts vs. EPA (2007).

There are two key parts to Rule 111. These sections contain key elements that are subject to interpretation, which means different administrations may define standards and acceptable solutions differently. The two key Rule 111 sections are:

1. **New Source Performance Standards (NSPS) - Section 111(b):** This part applies to new, modified, and reconstructed plants. It requires such facilities to use the best-demonstrated technology to minimize pollutant emissions. The standards are set based on the emissions achievable by employing the best system of emission reduction (BSER) that has been adequately demonstrated. These standards are designed to ensure new and upgraded facilities implement current pollution control technologies.

2. **Emission Guidelines for Existing Sources - Section 111(d):** This part applies to existing sources of pollution that are not covered by national emission standards for hazardous air pollutants. Under this provision, the EPA issues emission guidelines that states then use to develop plans to control emissions from existing sources. These guidelines typically set performance standards based on the best system of emission reduction for each type of source.

One area where different administrations may interpret Rule 111 differently is in defining the BSER. "Adequately demonstrated" technology can be viewed as anything from proven in demonstration plants to requiring the development of a full-scale supply chain and successful deployment at industry scale plants. A second area concerns what EPA will accept as a state plan for controlling existing plant emissions.

Under Section 111 (d), states must comply with the pollution guidelines EPA develops. Once EPA's guidelines are final, states must develop a State Plan (SP) indicating how they will comply. Historically, states have some flexibility in determining how they will comply. Their SPs are then submitted to EPA, which may approve them or deem them inadequate. If a state's plan is not approved or if it does not submit an SP, the EPA will impose a Federally mandated compliance plan.

EPA's current proposal sets limits for new and reconstructed gas-fired combustion turbines (CTs); existing coal, oil, and gas-fired steam generating units; and certain existing larger, more frequently used gas-fired CTs. Those limits are based upon emissions benchmarks set by high levels of carbon capture and storage or hydrogen-rich fuel blends. Stated differently, carbon capture sequestration/utilization (CCUS) and hydrogen co-firing are the BSERs on which EPA has based its new standards.

When issuing new standards, EPA is required to undertake a Regulatory Impact Assessment (RIA). For this current issuance, EPA assumed the following:

- A reference case (against which additional emissions reductions must be achieved) that already assumes significant post-IRA retirements of emitting sources and renewables adoption.
- Henry Hub natural gas prices of $1.90-$2 MBTUs from 2035-2040.
- Hydrogen costs $1/kg. (i.e., $7.40/MBTUs) in 2035 and $0.50/kg. in 2040
- Load growth from 4341 TWh in 2028 to 5050 TWh in 2040, a 1.3% CAGR.
- Adequate electricity transmission and hydrogen storage/delivery infrastructure is available.
- No impact on retail electricity costs, assumed to be $0.093/kWh in 2040. [28]

EPA's new standards vary by fuel source (coal & natural gas), new vs. existing, size, remaining life and capacity factor. An overview of EPA's preliminary rule standards follows, beginning with the more critical rules governing natural gas plants and then covering coal-fired generation:

EPA Guidelines for Natural Gas Power Plants

EPA provided guidelines for Natural Gas Power Plants in three categories.

1. **Low Load Combustion Turbines**
2. **Intermediate Load**
3. **Base Load**

Low Load Combustion Turbines:

These CTs are often used for meeting peak demand. The EPA targets such low-load combustion turbines with a performance standard that hinges on the utilization of lower-emitting fuels such as natural gas. EPA's emissions target allows an emission's *rate between 120 to 160 lb CO2/MMBtu*. The agency has decided not to propose Carbon Capture and Storage (CCS), or hydrogen co-firing for this category, citing the lack of cost-effective greenhouse gas (GHG) emission reductions from these methods.

Intermediate Load:

Standards for these NGCC and CTs are proposed in two phases.

Phase-1

The EPA recommends highly efficient simple cycle technology as the Best System of Emission Reduction (BSER) for intermediate-load gas plants. Recognizing the proven effectiveness of such technologies combined with improved operating practices, the EPA proposes a performance standard of *1,150 lb. CO_2/MWh-gross for these plants*.

Phase 2: Hydrogen Co-Firing Pathway:

The EPA sets a Phase 2 target for these plants to achieve an emission standard of 1000 lb CO_2 per MWh-gross by 2032. This target is based on using efficient, simple cycle technology combined with co-firing 30% low-GHG hydrogen. This approach aims to reduce emissions by integrating a significant proportion of cleaner hydrogen fuel into the energy mix.

Phase 3: Potential Hydrogen Co-Firing Pathway

There is no Phase III BSER component or standard of performance stipulated in the EPA guidelines.

Base Load (NGCC):

Phase-1:

For base load Electricity Generating Units (EGUs), the EPA suggests BSER based on highly efficient combined cycle technologies. For larger combustion turbines with a base load rating of 2,000 MMBtu/h or more, the proposed performance standard is 770 lb. CO_2/MWh-gross. For those with a base load rating of less than 2,000 MMBtu/h, the EPA proposed a range of 770 to 900 lb. CO_2/MWh-gross, varying with the specific base load rating.

Phase 2: CCS Pathway

For base load plants opting for CCS, a performance standard of 90 lb. CO_2/MWh-gross is set for 2035. This involves installing CCS technology capable of capturing 90% of CO_2 emissions, aligning with the EPA's goal of significantly reducing emissions from these high-capacity plants.

Hydrogen Co-Firing Pathway:

Base load plants adopting hydrogen co-firing must meet a standard of 680 lb CO_2/MWh-gross by 2032. This involves using efficient combined cycle technology and co-firing 40% low-GHG hydrogen, aiming to lower emissions by substituting a substantial part of their fuel with hydrogen.

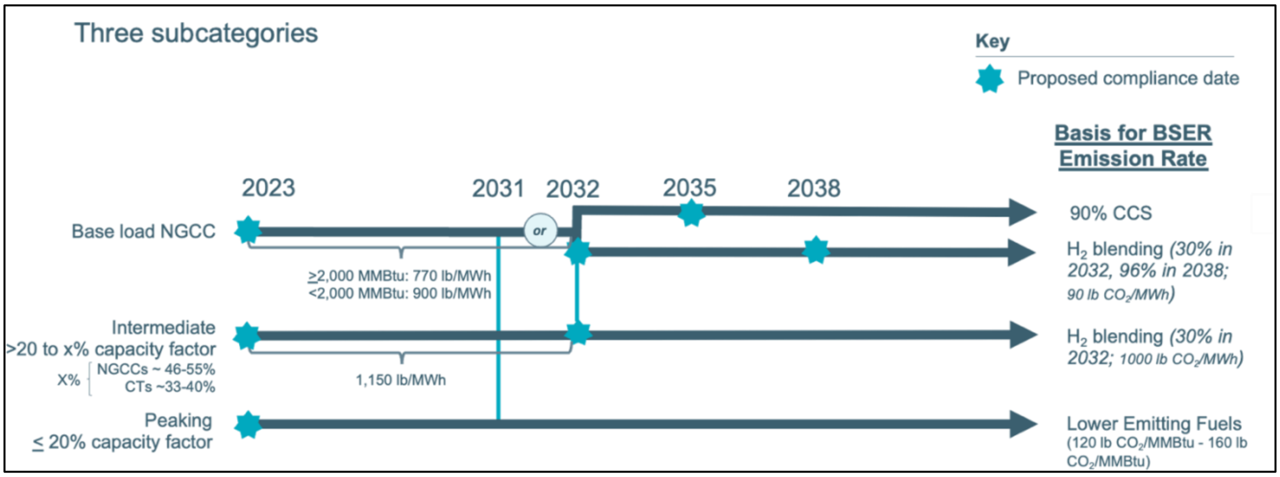
Phase 3: CCS Pathway:

There is no Phase III BSER component or standard of performance stipulated in the EPA guidelines.

Hydrogen Co-Firing Pathway:

A further reduction in emissions is proposed for 2038, with a performance standard of 90 lb. CO_2/MWh-gross. This phase is based on co-firing 96% low-GHG hydrogen, pushing base load plants towards almost complete reliance on hydrogen as a fuel source.

This chart summarizes the rules as they apply to all-natural gas-fired generation.



Sources:

EPA Guidelines for Coal-Fired Power Plants

EPA provided guidelines for Coal Power Plants in four categories.

1. **Long-Term Units (Coal Plants Planning to Operate Beyond 2040)**
2. **Medium-Term Units (Coal Plants Retiring by 2040)**
3. **Near-term Term Units (Coal Plants with Annual Capacity Factor Limit of Up to 20 Percent and Retiring by 2035)**
4. **Imminent Term Units (Coal Plants Retiring by 2032)**

Long-Term Units (Coal Plants Planning to Operate Beyond 2040):

The EPA's proposal for coal-fired power plants intending to operate beyond 2040 includes a requirement to implement Carbon Capture and Storage (CCS) technology. This technology should ensure 90% of CO2 emissions are captured, resulting in an 88.4% decrease in emissions per MWh. Plants must have CCS operational by 2030. The EPA's endorsement of CCS as the Best System of Emission Reduction (BSER) is based on its belief in its proven effectiveness at scale and cost-effectiveness when aided by the IRA's 45Q tax credit. Environmental and health impacts are deemed manageable.

Medium-Term Units (Coal Plants Retiring by 12/31/39):

The EPA suggests a distinct approach for coal plants scheduled to retire by 2040. Considering the reduced operational duration and the shorter window to benefit from the 45Q tax credit, the EPA views CCS as a less cost-effective option for these medium-term units. The proposed alternative is natural gas co-firing, which should account for 40% of the annual heat input and is expected to lead to a 16% decrease in CO2 emissions per MWh.

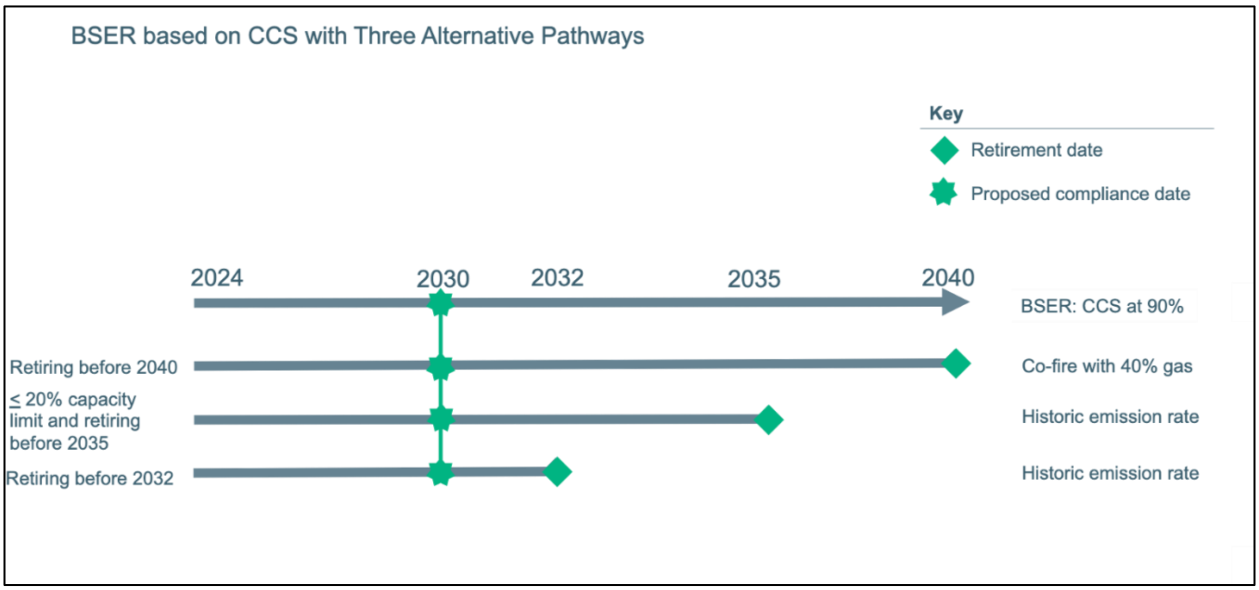
Near-Term Units (Coal Plants with Annual Capacity Factor Limit Up to 20 Percent and Retiring by 12/31/34):

For power plants with a longer operational horizon but limited to functioning as peaking units with a maximum capacity factor of 20 per cent, the EPA proposes that routine operation and maintenance practices suffice as the Best System of Emission Reduction (BSER), stipulating that emission rates should not exceed current levels. This strategy is considered already sufficiently demonstrated, as it aligns with existing operational standards, does not introduce additional costs, and does not negatively impact health, the environment, or energy systems. While this approach may not reduce emissions from present rates, the EPA asserts it will prevent any increase in emission rates over time and can be adjusted for performance variances between different units.

Imminent-Term Units–(Coal Plants Retiring by 12/31/2031):

Similar to near-term units, the EPA recommends routine operation and maintenance as the Best System of Emission Reduction (BSER), with an emphasis on maintaining current emission rates without increase.

This chart summarizes the rules as they apply to all coal-fired generation.



Appendix 2

EPA's Thinking on CCS/H2 BSERs and 'Adequately Demonstrated'

EPA believes CCS is Adequately Demonstrated

To support its proposal that CCS on combustion turbines is adequately demonstrated, EPA includes the following examples:

- **The Bellingham Energy Center's 40 MW slipstream food industry capture facility in Massachusetts operated from 1991 to 2005, capturing 86 to 95 percent of the CO2.**
- **The proposed 900 MW Peterhead Power Station NGCC in Scotland will be able to capture 90 percent of the CO2 and is projected to be operational by 2030 and**
- **An announced 1,800 MW NGCC in West Virginia will use CCS and will "begin operation later this decade.**

The following are the key observations from EPAs 111(d) on the cost of implementation of CCS.

- The 45Q tax credit is assumed to be maximized at $85/metric ton of CO2, subject to certain wage and apprenticeship conditions, and the total cost calculation for CCS considered a 30-year lifespan and the 12-year duration of the 45Q tax credit.
- EPA estimated that CCS costs are between $6 to $15/MWh or $19 to $44/ton of CO2 reduced, varying with the amortization period.
- EPA deems costs from $14.80 to $18.50/MWh for wet flue gas desulfurization and $98/ton of CO2e for methane reduction in other sectors as reasonable for comparative purposes.

EPA believes Hydrogen Co-firing is Adequately Demonstrated

To support its proposal that hydrogen co-firing is adequately demonstrated, EPA states that gas plants have co-fired small blends of up to 10 percent hydrogen without modification, and several power producers are developing hydrogen co-firing projects with the following examples:

- The Intermountain Power Agency project in Utah began planning to co-fire with hydrogen even before the IRA passed and made the project more economical. This project has begun transitioning the 1,800-MW coal-fired EGU to an 840-MW NGCC that will co-fire with 90 percent low-GHG hydrogen (via solar-powered electrolysis with geologic storage) upon startup in 2025 and combust 100 percent hydrogen by 2045.

- The 484 MW combined cycle combustion turbine Long Ridge Energy Generation Project in Ohio began operations in 2021 and "is designed to transition to 100 percent hydrogen in the future.

Hydrogen Costs compared to Natural gas.

Current Challenge: High cost of hydrogen compared to natural gas.

DOE's 2030 Goal: Reduce low-GHG hydrogen production cost to $1/kg.

Impact on LCOE: 30% hydrogen usage at 65% capacity factor → LCOE increase by $2.9/MWh.

IRA Tax Credits:
- Can potentially offset the increased costs of hydrogen.
- Aim for cost parity with natural gas for electricity generation.

"U.S. Treasury Proposed Regulations"
- Are very stringent in requiring that the electricity used to produce hydrogen be both 'clean' and 'additional.'
- The former pertains to definitions of what constitutes zero emissions electricity, e.g., does nuclear count if one considers the emissions involved in mining nuclear fuel?
- The latter requires that the electricity be surplus to the grid, i.e., it does not take power away from any existing customer.
- Collectively, these requirements amount to conditions likely to limit severely the projects which could qualify for the IRA 45 V hydrogen production tax credits.

Economic Outlook:
Achieving cost parity would make hydrogen a competitive, low-GHG alternative to natural gas and support the transition to a more sustainable energy mix.

Sources: https://www.gtlaw.com/en/insights/2024/01/clean-hydrogen-tax-credits-irs-releases-proposed-treasury-regulations

Appendix 3

Duke Energy's Net Zero 2050 Plan – 'the Base Plan'

Duke Energy's ambitious de-carbonization plan also responds to the accelerating economic growth in North and South Carolina. The plan projects a significant surge in load growth, estimated at around 35,000 gigawatt-hours over the next 15 years— this figure surpasses the annual electric generation of Delaware, Maine, and New Hampshire combined. To meet this burgeoning demand, the company proposes comprehensive infrastructure investments exceeding $90 billion (total Carolinas). This plan balances the use of dispatchable resources such as advanced nuclear, natural gas, and pumped hydro storage, with an increasing reliance on intermittent renewable energy. The core objective of this strategy is to achieve carbon neutrality by 2050. In setting this goal, Duke aligns with the sustainability goals of the region's largest employers.

However, Duke faces formidable challenges in realizing this objective. Duke's plans must all be submitted to and approved by the North Carolina Utilities Commission (NCUC). This body has made clear that Duke's first mission is to serve its customer base reliably. NCUC has also made clear that affordable power is a high priority. In reviewing Duke's CPIRP, the Commission made clear it considers the plan an 'approved roadmap' where each stage of the journey will be reviewed not just for de-carbonization progress but also as regards reliability and affordability. Duke's plan incorporates a record level of capital spending with a major number of plant shutdowns and site refurbishments. Such a level of activity will require Duke to carefully balance de-carbonization progress with a generation configuration that will contain costs and assure the grid remains reliable. The plans outlined below reflect Duke's efforts to carefully balance these objectives. The substantial risks associated with these plans are discussed at the end of this Appendix.

Strategic Development of Energy Portfolios:

Duke has undertaken a comprehensive approach to planning it's CPIRP, developing a total of 33 investment portfolios. These explore a broad spectrum of potential resource selections. The individual portfolios were then consolidated into three distinct pathways. Each pathway represents a different pace of energy transition, with corresponding Core Portfolios of generation assets unique to each pathway. Details of these pathways are provided below. They reflect plans for both Duke-North Carolina and its portion of South Carolina but give an accurate picture of the plans for this state.

In its August 2023 filing, Duke Energy presented its three main pathways for achieving carbon neutrality by 2050. Each of these pathways demonstrates a different approach to balancing CO_2 reduction, resource availability, cost, and reliability. All ultimately converge on the shared goal of carbon neutrality by 2050. The increasing load outlook is reflected in all Core

Portfolios, which show a notable increase in overall resource needs compared to previous plans. Central to Duke Energy's strategy is the leveraging of existing system resources. This includes extending the operational life of the 11 baseload nuclear plants and enhancing the flexibility of the existing natural gas fleet. Another significant component of this strategy is the extension and expansion of the Bad Creek pumped storage hydro facility, effectively doubling its capacity in what is termed "Bad Creek II."

While all three pathways reach the HB 951 and NCUC targets, they also involve different degrees of execution risk. In its August filing, Duke indicated pathway P3 is its base planning case. Duke's supplemental filing (1/31/24) showing even more projected load growth only reinforced the case for a pathway with lower execution risk.

Pathway-Based Approach to Carbon Neutrality:

Pathway 1 (P1 Base) outlines an extremely ambitious level of resource additions, which is challenging to attain by 2030. This pathway requires the addition of 1,600 MW of offshore wind, two hydrogen-capable combined-cycle generators totaling 2,720 MW, 6,600 MW of new solar (averaging 2,200 MW interconnected per year from 2027 to 2029, on top of the 3,000 MW already in advanced development), and over 5,300 MW of new battery energy storage (including nearly 300 MW currently in advanced development). The scale and timeline of these additions, along with the necessary transmission capacity, present significant permitting, and construction challenges.

Pathway 2 (P2 Base) represents a very aggressive deployment of new resources, aiming to achieve a 70% CO_2 emissions reduction by 2033. This pathway requires 1,600 MW of offshore wind and associated transmission, along with 6,300 MW of batteries (including projects in advanced development). Though less challenging than P1 Base, P2 Base still poses considerable execution hurdles.

Pathway 3 (P3 Base), while also aggressive, presents lower execution risks and costs compared to P2 Base. This is partly due to requiring 2,600 MW fewer batteries by 2033. It also allows for more cost-effective clean resources to fulfil the energy needs that would be served by offshore wind in P2 Base. P3 Base calls for approximately 25 to 30 major generation projects each year from 2030 to 2035. It balances reliably and cost-effectively serving growing customer needs and targets a 70% CO_2 emissions reduction by 2035.

Key Portfolio Considerations:

In each portfolio, Duke Energy has incorporated consistent forecasts for the impacts of Grid Edge programs. These programs, encompassing energy efficiency initiatives and new rate offerings, are designed to help 'shrink the challenge' of the energy transition. They aim to reduce both energy and peak demand needs on the system while simultaneously providing customers with more options to control their energy usage and bills.

A key aspect of Duke's approach in all portfolios is the significant expansion of renewable capacity. These however are not sufficient to replace the substantial coal capacity retired (~6 GW) and service growing load. More dispatchable generation must be added. This includes not only extending the life of existing nuclear units but also adding either advanced nuclear or Small Modular Reactors (SMRs). These reactors are considered fundamental to Duke's energy transition strategy. Alongside this, Duke plans to add baseload and dispatchable hydrogen-capable gas resources.

While offshore wind is not identified as a necessary component in the P3 Base through 2038, it does feature in several Pathway 3 Sensitivity Cases by 2035. This inclusion underscores the potential for offshore wind to become a viable option for Pathway 3. This option assumes more importance when Duke must consider complying with EPA's Rule 111 new standards.

Details of Duke Energy's specific Net Zero pathways are provided below:

By January 1 2035	Grid Edge	Coal Retirements	Solar	Battery	CT	CC	Onshore Wind	Pumped Storage Hydro	Advanced Nuclear	Offshore Wind
P1 Base	EE at least 1% of eligible retail sales	(-8.4 GW)	14.9 GW	6.1 GW	2.6 GW	2.7 GW	2.3 GW			2.4 GW
P2 Base	IWC growing to 96% (DEC) & 97% (DEP) circuits	(-6.2 GW)	11.8 GW	6.7 GW	2.1 GW	4.1 GW	1.7 GW	1.7 GW	0.6 GW	1.6 GW
P3 Base	Winter DR & CPP		11.9 GW	4.3 GW			2.1 GW			*0-1.6 GW*

By January 1 2038	Grid Edge	Coal Retirements	Solar	Battery	CT	CC	Onshore Wind	Pumped Storage Hydro	Advanced Nuclear	Offshore Wind
P1 Base	EE at least 1% of eligible retail sales		15.8 GW	6.1 GW	2.6 GW	2.7 GW	2.3 GW		3.0 GW	2.4 GW
P2 Base	IWC growing to 96% (DEC) & 97% (DEP) circuits	(-8.4 GW)	14.1 GW	7.0 GW	2.1 GW	4.1 GW	2.1 GW	1.7 GW	2.4 GW	1.6 GW
P3 Base	Winter DR & CPP		14.6 GW	6.0 GW	3.0 GW		2.3 GW			*0-1.6 GW*

Note 1: Coal retirements are dependent on addition of resources shown.

Note 2: New Solar includes solar paired with storage, excludes projects currently in advanced development.

Note 3: IVVC = Integrated Volt/VAR Control.

Note 4: CPP = Critical Peak Pricing.

Note 5: Battery includes batteries paired with solar.

Note 6: Offshore wind was not selected in P3 Base in the Base Planning Period however may be an option depending on resource need and market conditions.

Note 7: Bad Creek II Pumped Storage Hydro is projected to come into service by mid-2033; for planning purposes, the modeling reflects this resource coming into all resource portfolios at beginning of year 2034.

Sources:

Evaluating Portfolios for Cost Efficiency, Clean Resource Integration, and Transition Risk Management

CAROLINA RESOURCE PLAN PORTFOLIOS	P1 Base		P2 Base		P3 Base	
DEC/DEP COMBINED SYSTEM RESOURCES [NAMEPLATE MW] START OF YEAR	**2033**	**2038**	**2033**	**2038**	**2033**	**2038**
Total Contribution from Grid Edge & Customer Programs[1]	2,087	2,536	2,087	2,536	2,087	2,536
Incremental System Solar (excl. ~3,000 MW of projects in dev.)	13,350	15,750	8,775	14,100	8,775	14,625
Incremental Onshore Wind	1,500	2,250	1,200	2,100	1,200	2,250
Incremental Offshore Wind	2,400	2,400	1,600	1,600	0	0
Incremental Advanced Nuclear Capacity	0	3,000	0	2,400	0	2,400
Incremental Energy Storage[2]	6,374	8,054	6,314	8,894	3,694	7,954
Incremental Gas (CC)[3]	2,720	2,720	4,080	4,080	4,080	4,080
Incremental Gas (CT)[3]	2,550	2,550	2,125	2,125	2,125	2,975
Remaining Coal Capacity[4]	2,162	0	3,064	0	4,473	0
Total Coal Retirements [MW] by End of 2035[4]	**8,445**		**8,445**		**8,445**	
PORTFOLIO COST (2033/2038)	**2033**	**2038**	**2033**	**2038**	**2033**	**2038**
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP/DEC Combined System) [$/month] 2033|2038[5]	$60	$70	$48	$56	$35	$55
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP) [$/month] 2033|2038[5]	$86	$77	$72	$63	$41	$48
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEC) [$/month] 2033|2038[5]	$41	$65	$32	$51	$30	$59
	2038	**2050**	**2038**	**2050**	**2038**	**2050**
Present Value Revenue Requirement (PVRR) (DEP/DEC Combined System) through 2038|2050 [$B]	$76	$139	$69	$124	$66	$119
PVRR (DEP) [$B] through 2038|2050	$34	$62	$28	$53	$26	$48
PVRR (DEC) [$B] through 2038|2050	$42	$77	$40	$71	$40	$71
INCREASINGLY CLEAN RESOURCE MIX	**2033**	**2038**	**2033**	**2038**	**2033**	**2038**
CO_2 Intensity (DEP/DEC Combined) [lbs/MWh]	217	131	267	163	313	182
Year in which 70% CO_2 Reduction Achieved	2030		2033		2035	
RELIABILITY & FLEXIBILITY	**2033**	**2038**	**2033**	**2038**	**2033**	**2038**
95th Percentile Expected Net Load Ramp (MW/hr)	12,122	13,581	9,206	12,553	9,201	12,880
Average CC Starts per Unit per Year	86	90	39	64	60	81
ENERGY TRANSITION RISK ASSESSMENT	**2033**	**2038**	**2033**	**2038**	**2033**	**2038**
Cumulative Nameplate MW Additions of Resources with Limited Operational History in the Carolinas[6]	10,274	15,704	9,114	14,994	4,894	12,604
Cumulative Nameplate MW Additions, Combined Carolinas System[7]	31,907	39,737	27,107	38,312	22,887	37,297
Cumulative Nameplate MW Additions as % of Current Combined Carolinas System	73%	91%	62%	88%	53%	86%
Cumulative Capital Dollar Requirement, Combined Carolinas System [$B]	$85	$130	$59	$101	$44	$92
Overall Pathway Risk Related to Cost, Reliability, and Plan Execution	●		◕		◑	

Note 1: Includes winter peak impact of load modifiers (utility-sponsored energy efficiency, behind-the-meter solar, critical peak pricing), integrated Volt-VAR control (IVVC) and demand response programs.
Note 2: Includes stand-alone storage, paired storage, pumped storage hydro and forecast.
Note 3: New natural gas facilities will be capable of burning zero-carbon hydrogen in the future; hydrogen blending is assumed to begin in 2035.
Note 4: Cliffside 6 continues to operate on 100% natural gas.
Note 5: Average retail rate impact across all customer classes applied to representative residential bill. Note 6: Includes onshore wind, offshore wind, battery energy storage and advanced nuclear.
Note 7: Includes solar and battery projects currently in advanced development.

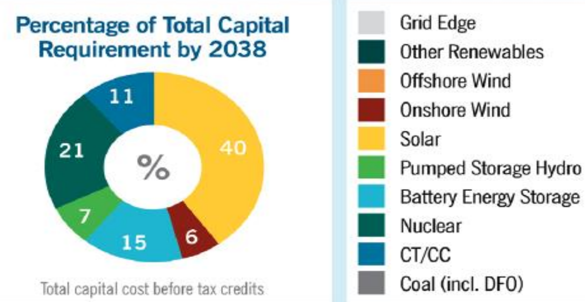
The primary distinction among the Pathways lies in their pace of the transition. Pathways with more aggressive schedules impact relative costs and increase the risks associated with project cost and reliability Pathway 1, which aims to meet the Interim Target by 2030, is judged to pose the greatest level of strategy execution risk.

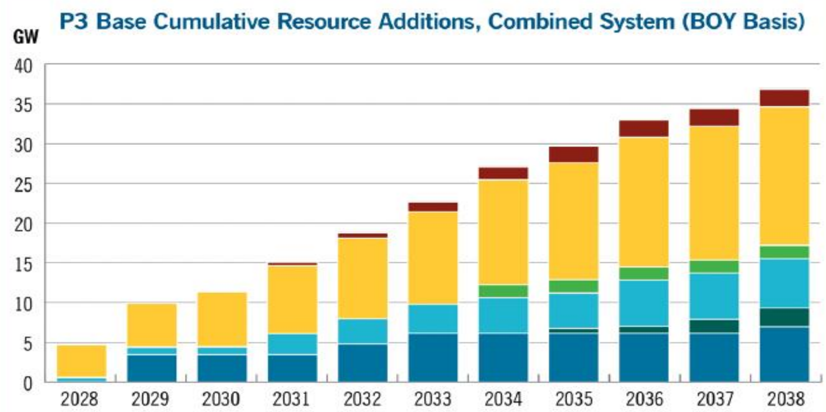
Pathway 2 aims to achieve the Interim Target by 2033 and promises a 5% lower cumulative CO2 output through 2050. However, its accelerated transition pace versus P3 also involves heightened costs and risks. Pathway 2's Core Portfolio is projected to cost around $5 billion more by 2050. The short-term customer bill impact is also significant, with costs rising at a CAGR approaching 4% through 2033. The critical cost and risk differentiator between Pathways 2 and 3 is Pathway 2's expedited reliance on 1,600 MW of offshore wind, supported by a significantly accelerated deployment of battery energy storage resources. P 3's defining characteristic is thus the flexible view it takes on offshore wind. P3 could include 1.6 GW of offshore wind or leave it completely out of the executed plan.

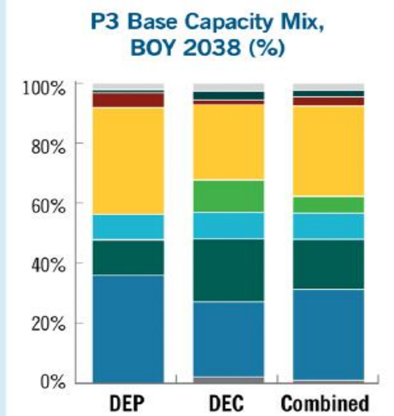
In conclusion, Pathway 3 (P3 Base) is Duke Energy's favored course of action as of this moment P 3 seeks to balance the imperative of transitioning to a more sustainable energy mix with the real-world considerations of cost, reliability, and execution feasibility. That said, the execution risk associated with Duke retiring 6.2 GW of coal-fired capacity by 2035 while constructing 25-30 major generation projects annually between 2030 and 2035 should not be underestimated. Duke's Base Plan, Pathway 3, will be very challenging to pull off.

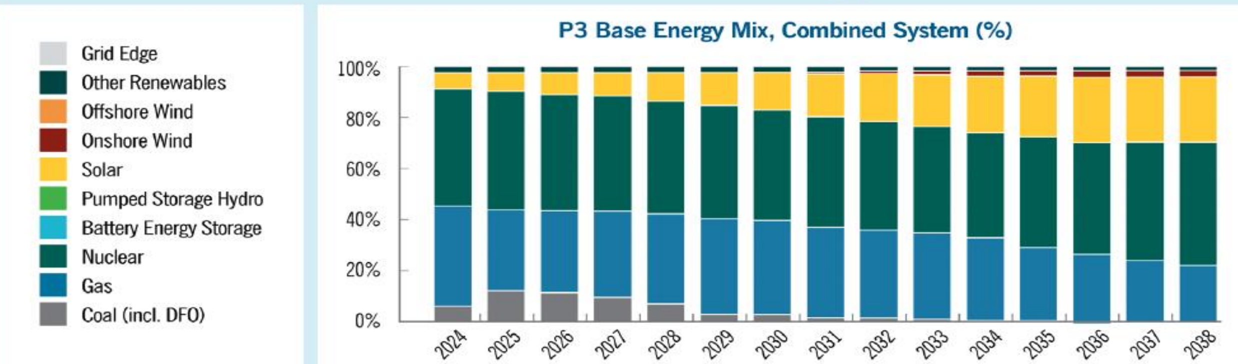
P3 Base Summary

P3 Base		2038	2050
PVRR ($B)	Combined System	$66	$119
	DEP PVRR	$26	$48
	DEC PVRR	$40	$71
		2033	**2038**
BILL IMPACT	Combined System CAGR	2.8%	2.6%
	DEP CAGR	3.0%	2.2%
	DEC CAGR	2.6%	2.9%
	Year in which 70% target is met	2035	









P3 Coal Retirements by Year (MW, effective by January 1 of year shown)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
DEP						1,053		713			1,409		
DEC		426*				760		546	1,318				2,220
TOTAL		**426***				**1,813**		**1,259**	**1,318**		**1,409**		**2,220**

*Allen Units 1 & 5 are planned to retire by December 31, 2024.

Sources: Duke Energy Inc., Integrated Resource Planning

Appendix 4

How Duke would comply with the new EPA Rules – “The Compliance Case”

Duke Energy already plans to retire virtually all of its North Carolina coal plants by the early 2030s. One, albeit large, plant may need to be retired one year earlier than currently planned.

Thus, the Rule's principal impact concerns Duke’s natural gas fleet. In parallel with its large renewable buildout, Duke’s P 3 plan foresees an expansion of gas-fired CT and CCNG generation. Whereas Duke’s whole system contained 25 GW of gas-fired generation in 2019, Duke’s plans foresee this fleet growing to 36+ GW in 2035. Duke sees this growth in gas-fired capacity as necessary to ensure its generation has both the load-following and the baseload capacity needed to complement the low capacity, intermittent nature of growing, predominantly solar renewables.

As noted above, Duke’s P 3 Pathway shows the following base generation additions/ deletions in 2035:

GW Coal	Solar	Battery	NG-CT	NG-CCNG	Onshore Wind	Pump Hydro Storage	Advanced Nuclear	Offshore Wind
-6.2	**11.9**	**4.3**	**2.1**	**4.1**	**2.1**	**1.7**	**0.6**	**0 to 1.6**

Collectively this amounts to adding over 20 GW net to the current Carolinas system with a further 1.6 GW offshore wind possibility. Said differently, Duke Carolinas’ current system grows by about 2/3.

To comply with the Rules, Duke would change the above Pathway in the following manner:

Estimated capacity addition changes assuming 50% CF of CCs

Capacity Delta (MW) vs P3	2025	2030	2035	2040	2045	2050
Solar	0	0	0	-1,800	-1,875	-1,575
On-Shore Wind	0	0	-450	-600	-150	0
Off-Shore Wind	0	0	1,600	1,600	1,600	800
Storage	0	0	-600	-2,470	-1,790	-1,290
Nuclear	0	0	-300	0	0	-600
CTs	0	0	850	0	-425	-425
CCs	0	0	1,359	1,359	1,359	1,359
Coal	0	0	0	0	0	0
Coal DFO	0	0	0	0	0	0
Total Max Capacity	0	0	2,459	-1,911	-1,281	-1,731

Assume 100% of offshore wind is NC, otherwise, allocate changes 76% to NC.

Reflecting these changes in the Base P 3 table above, the full 2035 Compliance Case looks as follows:

Net 2035 GW vs. Base Plan

Coal	Solar	Battery	NG-CT	NG-CCNG	Onshore Wind	Pump Hydro Storage	Advanced Nuclear	Offshore Wind
-6.2	11.9	3.7	3.0	5.5	1.6	1.7	0.3	1.6

Putting this in perspective, net additions rise to 23.1 GW, another 3 GW above the base P 3 Pathway. Two-thirds of this increase comes from additional gas-fired plants as the existing fleet is now running below 50% capacity. A major offshore wind addition helps compensate for the loss of onshore wind, storage, and nuclear capacities.

The full effects of these changes and the Compliance Plan's execution risks are discussed below.

Sources: Duke Energy Inc., Integrated Resource Planning

Appendix 5

The Differential Case: Duke Energy's Compliance Plan" Capacity Additions

The Differential case highlights the key differences between the two (compliance case and base P 3 plan) scenarios. Here it should be noted that in the Compliance Case Duke becomes an even more 'gas + offshore wind' utility as it moves on towards 2050. Essentially, Duke adds 4 GW each of CCNG and Offshore Wind while rebalancing with reductions in Storage, Onshore Wind and Nuclear. Advanced nuclear will remain a major contributor by 2040. Revisiting the Net Additions chart illustrates these directions going out to 2040 and 2050.

Differential Case' capacity additions vs. P 3 changes assuming 50% CF of CCs

Capacity Delta (MW) vs P3	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Solar	0	0	0	-1,800	-1,875	-1,575
On-Shore Wind	0	0	-450	-600	-150	0
Off-Shore Wind	0	0	1,600	1,600	1,600	800
Storage	0	0	-600	-2,470	-1,790	-1,290
Nuclear	0	0	-300	0	0	-600
CTs	0	0	850	0	-425	-425
CCs	0	0	1,359	1,359	1,359	1,359
Coal	0	0	0	0	0	0
Coal DFO	0	0	0	0	0	0
Total Max Capacity	0	0	2,459	-1,911	-1,281	-1,731

Assume 100% of offshore wind is NC, otherwise, allocate changes 76% to NC

As noted above, the Compliance Plan incorporates these changes into the P 3 Base Plan. Measured against 2024, the Base P 3 plus the Compliance Case 2040 full net capacity additions show Duke 'solar + gas + offshore wind' trajectory:

2040 Net GW P3 + Compliance vs. 2024

Coal	Solar	Battery	NG-CT	NG-CCNG	Onshore Wind	Pump Hydro Storage	Advanced Nuclear	Offshore Wind
-8.4	12.8	2.9	4.0	6.7	1.2	1.7	2.1	3.2

Taken holistically, by 2040 in the 'Compliance Case' Duke proposes to:

1. **Retire all (8.4 GW) of coal capacity.**
2. **Build 15.7 GW of solar + battery storage.**
3. **Build 10.7 GW of gas-fired plants.**
4. **Build 2.1 GW of advanced nuclear.**
5. **Build 4.4 GW of wind, 2/3 of its offshore.**

In terms of plan execution risks, Duke has never built advanced nuclear or offshore wind. The planned solar + storage capacity is more than 2X of what it has built to date. Finally, Duke has never operated a generation fleet where roughly 1/3 of its capacity was intermittent wind and solar. The execution risks associated with such a plan must be considered formidable. Cost overruns and schedule delays are likely.

Complying with the Rules positions 2032-35 as the critical dates for planning. It is right before those years that Duke's CC gas-fired plants would have to install CCS, H2-cofiring or be operated below 50% capacity. Since Duke, for good reasons, considers the first two options infeasible, compliance forces Duke to build the additional gas and bring forward the offshore wind planned for later in P 3.

Duke positions Offshore wind as the 'marginal project' in its planning, i.e., this wind capacity is the major change from P 3 that makes the Compliance Case 'work.' The wind project provides both zero emissions and the presumed low electricity costs that enable the plan to meet its multiple goals. Since Duke has never built such a project and since recent developments in U.S. offshore wind underscore both cost and execution challenges, it is distinctly possible this 1.6 GW of capacity will not prove feasible to build by 2035. Among other things, the NCUC may reject such a project for reasons of cost and reliability. Should something of this sort happen, Duke would be left with 'more natural gas + onshore renewables & storage' as its remaining compliance options.

As of today, Duke faces constraints on natural gas supplies. It continues to hope that the Mountain Valley Pipeline (MVP) will bring some relief, though legal challenges by environmental groups are ongoing. MVP by itself cannot supply the gas needed for the major gas-fired additions cited above. Some breakthroughs in gas supply infrastructure are going to be needed to enable the Compliance Case to be realized.

All things considered; Duke faces considerable execution risks. Its base P 3 plan is already ambitious. The Compliance Case exacerbates P 3's risks by requiring more gas and bringing forward major Offshore Wind capacity. Since P 3 is crafted to produce the same emissions reduction as the Compliance Case, one must ask 'What is the benefit' of forcing Duke into the Compliance Case as opposed to enabling P 3 to proceed?

Sources: Duke Energy Inc., Integrated Resource Planning

Appendix 6

North Carolina Economic Competitiveness and Outlook

North Carolina was performing well before the 2020 pandemic. Unemployment was low at 3.6%. The state was already attracting significant immigration. Unemployment soared to over 12% during 2020 but the state recovered quickly after that. High job growth and labor market participation relative to other states suggested that North Carolina enjoyed a strong competitive position.

Many factors contribute to North Carolina's economic competitiveness. Moderate climate and available land are attractive natural resources. North Carolina is a 'purple state' politically, with a Democrat governor and a Republican majority legislature. This combination has resulted in moderate governance and a consensus around being business friendly. The state has adopted numerous business-friendly policies. In recent years it has steadily lowered corporate income taxes to the current 2.5% level. Personal income taxes have also declined from 8% to 4.9%. Yet, these tax cuts have been more than compensated for by growth, and the state boasts both an AAA debt rating and a substantial budget surplus.

These conditions have enabled the state to invest heavily in 'public goods.' North Carolina has continuously upgraded infrastructure for such basics as transportation, broadband, sewer systems, water supply and power. It also has invested in public education, helping to create a workforce capable of staffing small- and large-scale manufacturing as well as high-tech industries. Finally, the state has modernized aspects of its legal and regulatory systems. Both workman's compensation and environmental laws have been updated to strike a balance between businesses and other stakeholders.

A favorable cost of living and cheaper housing costs are two other advantages enjoyed by North Carolina. These advantages continue to attract immigration across multiple age groups. Some come to the state for its employment opportunities while others retire here to enjoy the moderate climate, recreational opportunities represented by beaches and mountains, low taxes, good health care and the lower cost of living. North Carolina's cost of living index is 9% lower than the U.S. average while housing costs are almost 15% below the national average. Collectively, these factors foster strong migration into the state. North Carolina's population grew by 133,000 between 2021-2022. Almost all of this growth was net migration from other states. Births within the state also slightly outpaced deaths.

This impressive set of competitive advantages has been recognized by both large and small businesses. In 2022 alone North Carolina attracted $19.2 billion in new investment, creating 29,000 new jobs in the process. This performance, in turn, has been reflected in surveys where states are ranked as places 'To Do Business.'

To rank America's Top States for Business in 2023, CNBC scored all 50 states on

86 metrics in 10 broad categories of competitiveness. Each category is weighted based on how frequently states use them as a selling point in economic development marketing materials. The study ranks the states based on the attributes they use to sell themselves. Its criteria and metrics were developed in consultation with a diverse array of business and policy experts, and the states. Using this methodology, states can earn a maximum of 2,500 points. The states with the most are America's Top States for Business. The top five states in 2023 and their specific scores are listed below:

AMERICA'S TOP STATES FOR BUSINESS 2023

OVERALL RANK	STATE	WORK-FORCE	INFRA-STRUCTURE	ECONOMY	LIFE, HEALTH & INCLUSION	COST OF DOING BUSINESS	TECHN & INNOVATION
1	North Carolina	1	16	3	34	18	6
2	Virginia	7	10	13	16	34	15
3	Tennessee	9	3	5	43	7	27
4	Georgia	8	1	4	39	27	19
5	Minnesota	17	3	24	4	39	4
6	Texas	2	24	2	50	16	8

This review shows that North Carolina's economic performance stems from multiple competitive advantages. No one factor is responsible for the state's strong economic growth. This diverse set of advantages suggests that North Carolina's economy is resilient and should not suffer unduly from a setback in one area. That said, a major public disruption, like a series of power failures/blackouts, could materially impact the state's favorable reputation for power and reliability and cause a pause in both incoming investment and population migration.

Sources: https://www.cnbc.com/2022/07/13/americas-top-states-for-business-2022-the-full-rankings.html

Conclusions & Recommendations

The EPA's promotion of carbon capture and hydrogen co-firing for fossil fuel power plants as 'adequately demonstrated' is strained at best. The fact that such solutions are being tested at a couple of pilot plants is little assurance they will be available at scale in time to meet the 2030-34 deadlines for plant conversions. Without question, these solutions are more expensive than current natural gas-fired operations. EPA counters this concern by citing IRA subsidies. These may not survive future political outcomes and in any case may not prove adequate when the costs of applying CCS or hydrogen co-firing at scale are defined. By far the biggest uncertainty concerns infrastructure, especially pipelines. If these cannot be built for predictable costs and on predictable schedules, it is difficult to see how a state like North Carolina will be able to import the hydrogen and/or export the CO2 necessary to adopt EPA's desired solutions.

Proponents tout 'Green Hydrogen' made with renewable power as very cheap to produce. This can only be the case if the solar or wind in question is 'surplus,' and thus of low value. Otherwise, using electricity to make hydrogen to then make electricity is inefficient and bound to be expensive. There is no 'surplus' solar or wind in North Carolina's outlook. All such generation in Duke Energy's aggressive buildout is expected to serve demand. This is especially the case as Duke's load projections have been increasing. Moreover, cost-effective hydrogen via electrolysis requires a 24/7 manufacturing process. Since solar and wind are only available during limited times, 'green hydrogen' production will require combining them with other forms of low-carbon electricity. This combination will add cost to any NC 'green' hydrogen production. Adding in-state electrolysis to Duke's projected load increases also means that more, and likely more expensive, power sources must be added to the firm's 'Compliance Case.'

We thus conclude that EPA's mandated solutions are unrealistic for North Carolina. Moreover, we suspect that EPA knows this to be the case for North Carolina and several other states. EPA's recent public discussions about having tools for assuring grid reliability signal concern on this front and acknowledge the risks associated with the hard deadlines set in their preliminary rulemaking. Private conversations with the Agency reinforce the impression that the EPA is aware of grid reliability as a major issue.

How then should the aggressive nature of EPA's preliminary Rule be understood? On one level, it represents an 'opening position' by the Agency. EPA anticipates feedback and criticism and plans to reflect it in their final Rule. In this sense the Rules represent a bargaining position tabled by the Agency to the various utilities and states. There is also evidence that the Rules are a political document issued in a presidential election year by an Administration interested in firming up support from environmental groups in its coalition. Finally, there is every likelihood that any EPA final Rule resembling its preliminary version will be challenged in court. Given recent Supreme Court rulings, such challenges may indeed prove successful. However, there is no guarantee of such an outcome and the time involved to process such challenges through the trial and appellate courts is uncertain.

Perhaps the best outcome would be for the Agency to delay its final rulemaking until after the 2024 election. It could then put out a final rule reflecting much of the input from various states, ISO/RTOs and utilities. Appropriate flexibilities could be built into the deadlines, the reliability mechanism could be made forward looking and State Plans that met emissions targets via any/all means could be welcomed. This would provide a state like North Carolina with the ability to continue implementing its approved plans independent of what was happening in any subsequent litigation.

Will the EPA adopt this approach? The likely answer is “at best in part.” Expect some modifications aimed at shoring up power reliability. However, EPA is likely to retain its hard deadlines which it believes are essential for prodding the states to move forward on the difficult path to decarbonization.

The other takeaway from this assessment is the need for infrastructure reform to unlock the ability to build needed connections between ‘the best places’ to create Transition assets and where their output needs to be delivered. As noted, missing infrastructure is the key barrier rendering EPA’s preferred solutions as unrealistic for NC. This likely is the case for other states as well. Pipelines and Long-Distance Power Transmission are the principal examples of necessary Transition assets that have become too costly or politically impossible to build. As things stand there is no CCS or hydrogen production industry ready to serve power providers. Unless EPA expects each utility to ‘build their own’ CO_2 storage and hydrogen manufacturing next to their existing gas plants, such vital pieces of infrastructure will have to be built or CCS and hydrogen co-firing will remain little more than interesting ideas. A ‘build-your-own’ solution will be suboptimal in terms of cost, only adding unnecessary expense to an already costly Transition.

Infrastructure reform encompasses permitting reform but involves more than that. It also involves limitations on the legal challenges that may be mounted under existing environmental laws, streamlining environmental reviews by multiple agencies, and reinforcing eminent domain rights to overcome local NIMBY opposition.

The EPA has an opportunity, when it incorporates industry feedback into its Final Rule, to emphasize the case that infrastructure reform is essential to realizing its decarbonization vision.

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