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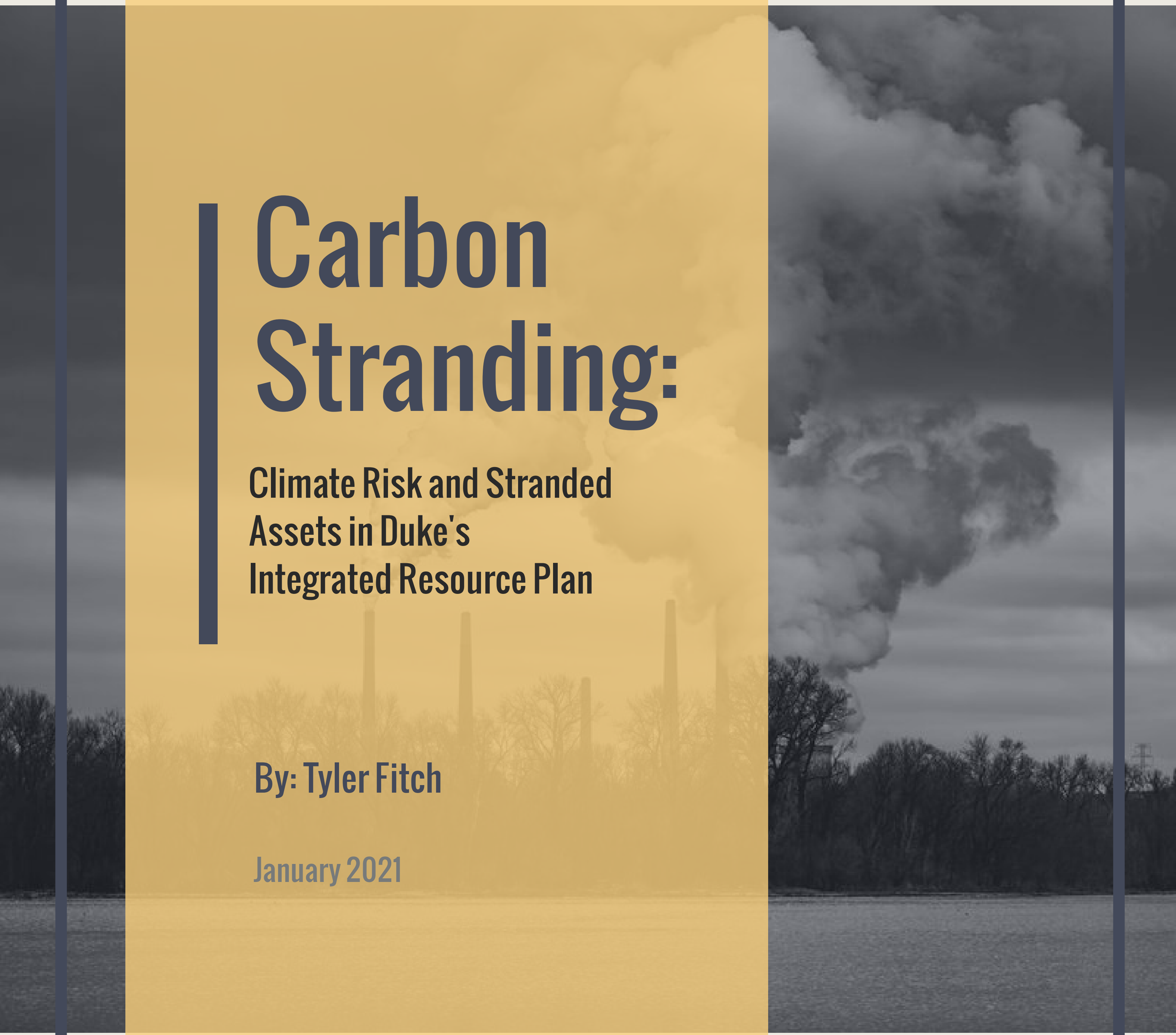

Carbon Stranding:

Climate Risk and Stranded Assets in Duke's Integrated Resource Plan

By: Tyler Fitch

January 2021

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Executive Summary

Climate change is disrupting the electric utility industry, and electric utilities and the regulators who oversee them must adapt. When utilities craft their integrated resource plans—15-year future roadmaps for new investments in power generation—it is critical that they address the physical, regulatory, economic, and financial impacts of changes to our climate and the emerging social and economic response. Given the decades-long lifetime of new power plants, investments made now will face climate-related stresses, shocks, and pressures that are substantially stronger than those experienced today. If integrated resource plans do not respond to this reality, utilities and regulators risk approving a plan that does not provide the most affordable, reliable, and sustainable electricity for their customers. Ultimately, ratepayers bear the burden of paying for integrated resource planning that is not sufficiently resilient to climate-related risks and opportunities.

This report examines utility integrated resource planning in light of climate-related risks and opportunities. Specifically, the report assesses the climate-related risks to investments in new fossil-fueled power plants, including being outcompeted by new, economically competitive technology, affected by climate-amplified physical phenomena, or rendered unusable because of constraints on carbon emissions. Investments that are brought offline before the end of their planned life in this way are referred to as 'stranded' assets, because the utility is unable to realize some of the expected value of their investment when it is unable to be operated as expected. Although the burden of stranded asset costs should be borne by utility shareholders in the abstract, stranded asset costs are more often assigned to ratepayers in practice.

Duke Energy Corporation's 2020 Integrated Resource Plans in North and South Carolina provide helpful case studies for assessing the risk of stranded assets. The Plans are the first filed in the Carolinas since Duke Energy's September 2019 commitment to reach net-zero carbon emissions by 2050, and regulators, legislators, and executive agencies across both states have indicated an elevated interest in climate-related risks and opportunities. Climate-related risks to carbon-emitting generation

notwithstanding, the Plans contemplate a 9.6 gigawatt addition of new gas-fired generation capacity in their baseline scenarios – one of the largest proposed expansions of fossil generation capacity of any utility in the United States.

Under climate-related risks, expanded investment in carbon-emitting generation could pose new risks to ratepayers. The report uses the term **'carbon stranding'** to refer to generation assets that would need to be either run less frequently or removed from the portfolio altogether in order to comply with carbon constraints. In this case, applicable carbon constraints are Duke Energy's corporate carbon commitment and the carbon emissions goals articulated by the state of North Carolina. While carbon commitments are just one of several vectors of climate-related risks and potential for stranding to these investments, it is used in this analysis as a proxy for climate risk generally.

The carbon stranding analysis conducted in this report finds that if Duke Energy pursues the investment plan contemplated in its Integrated Resources Plan, a substantial portion of its power plant fleet will need to be taken offline to meet existing carbon commitments. Without regulatory intervention, ratepayers will continue to pay off these plants for decades, even while they remain neither used nor useful. Carbon stranding costs to ratepayers are on the order of tens or hundreds of millions of dollars per year. In total, this analysis finds that carbon stranding costs from existing and proposed investments in these Integrated Resource Plans will be **$4.8 billion, or $900 in present-value costs for every residential Duke Energy customer in the Carolinas.**

Key findings of this report are below:

- **Stranded assets represent a salient risk for ratepayers.** Utilities are typically required to prove that their assets are 'used and useful' in order to be able to profit from their investment. In practice, however, utilities have enjoyed a presumption of used and usefulness. Even as the cost decline of renewables renders the fossil plants uneconomic, utility managers are incented to keep emitting resources online as long as possible. Although utility management is aware of the potential for stranded assets, utility executives and shareholders have generally expressed confidence that the burden for paying stranded asset costs will lie with ratepayers.

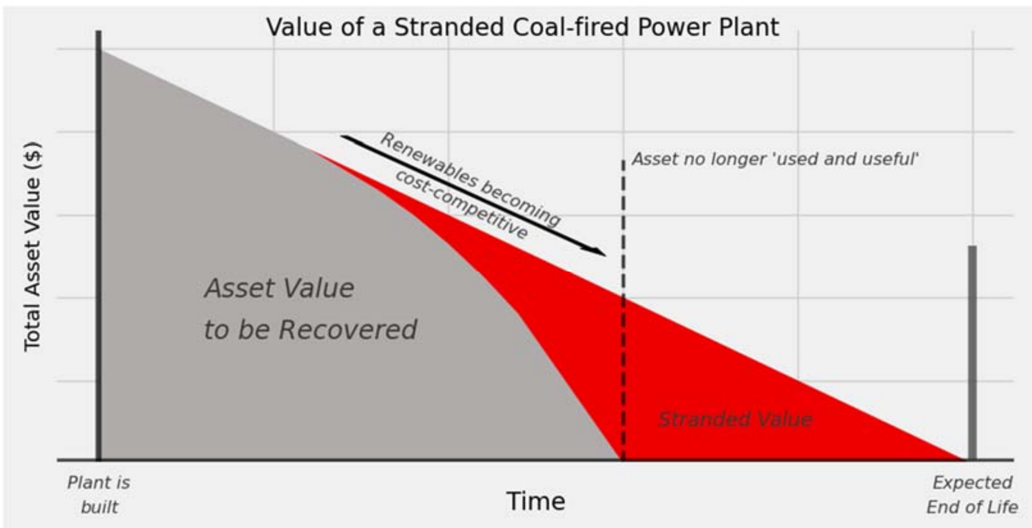

Figure ES-1. *Asset value over time for a hypothetical stranded asset*

- **Climate-related risks are increasingly shaping the present and future of the electricity grid.** Physical, financial, economic, regulatory, and reputational risks are material risks for Duke's operating companies in the Carolinas.

Table ES-1. *Summary of Climate-related Risks for Duke Energy's Companies in the Carolinas*

Type of Risk	Duke Energy Exposure in Carolinas
Physical	2020 North Carolina Climate Science Report found that "large changes in North Carolina's climate, much larger than at any time in the state's history, are ***very likely.***"[1] A Moody's analysis found Duke among the most at-risk utilities to flooding.[2]
Financial	BlackRock, Duke Energy Corporation's third-largest shareholder, claims climate risks are driving a "fundamental reshaping of finance."[3] The firm voted against boards of directors 55 times during 2019-2020 due to lack of climate progress.[4] Increased focus on environmental, social, & governance (ESG) issues are driving Duke investor attention.[5]
Economic	Renewable energy technologies are outcompeting conventional fossil-fueled generation, even on a subsidy-free basis.[6] Expert analysis finds that portfolios of clean energy resources could economically out-compete existing fossil generation by the mid-2020s.[7]
Regulatory	North Carolina's Clean Energy Plan contemplates future policies to decarbonize the electric power sector, including accelerated coal retirements, market-based carbon reduction programs, clean energy standards, or a combination of these standards.[8]
Reputational	Duke Energy's existing decarbonization goals are a public commitment, and the corporation's reputation and social license could be damaged if the commitment is not upheld. In a recent survey, Deloitte found that "the math doesn't add up" for Duke's decarbonization plan.[9]

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[1] Kunkel, K.E., D.R. Easterling, A. Ballinger, S. Bililign, S.M. Champion, D.R. Corbett, K.D. Dello, J. Dissen, G.M. Lackmann, R.A. Luettich, Jr., L.B. Perry, W.A. Robinson, L.E. Stevens, B.C. Stewart, and A.J. Terando, (2020). North Carolina Climate Science Report. North Carolina Institute for Climate Studies, 233 pp. Retrieved at: https://ncics.org/nccsr.

[2] Morehouse, C., (2020, January). "Ameren, Xcel, Dominion, Duke among most at-risk from changing climate: Moody's." *Utility Dive*. Retrieved at: https://www.utilitydive.com/news/ameren-xcel-dominion-duke-among-most-at-risk-from-changing-climate-mood/570789/.

[3] Fink, L. (2020). A Fundamental Reshaping of Finance. *BlackRock.* Retrieved at: https://www.blackrock.com/us/individual/larry-fink-ceo-letter.

[4] Partridge, J., (2020, September). "BlackRock votes against 49 companies for lack of climate crisis progress." *The Guardian.* Retrieved at: https://www.theguardian.com/business/2020/sep/17/blackrock-votes-against-49-companies-for-lack-of-climate-crisis-progress.

[5] Duke Energy Carolinas (2020, September). Duke Energy Carolinas Integrated Resource Plan 2020 ("DEC IRP Report"). NCUC Docket No. E-100, Sub 165. p. 93.

[6] Lazard, (2020, October). Levelized Cost of Energy and Levelized Cost of Storage — 2020. Retrieved at: https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2020/.

[7] Teplin, C., Dyson, M., Engel, A., Glazer, G., (2019). The Growing Market for Clean Energy Portfolios. Rocky Mountain Institute. Retrieved at: https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants/.

- **The economic and policy context for Duke Energy's 2020 Integrated Resource Plans (IRPs) is cause for greater focus on a climate-resilient path.** Concern around climate-related risks have increased at the state and national level since Duke Energy's 2018 IRPs in the Carolinas. Legislation in South Carolina and executive action in North Carolina are driving increased scrutiny on resource planning, and the North Carolina Utilities Commission acknowledged the risks of stranded assets in its response to a 2019 update of the 2018 IRPs.[10] The 2020 IRPs are also the first in the Carolinas since Duke Energy's corporate net-zero carbon commitment.

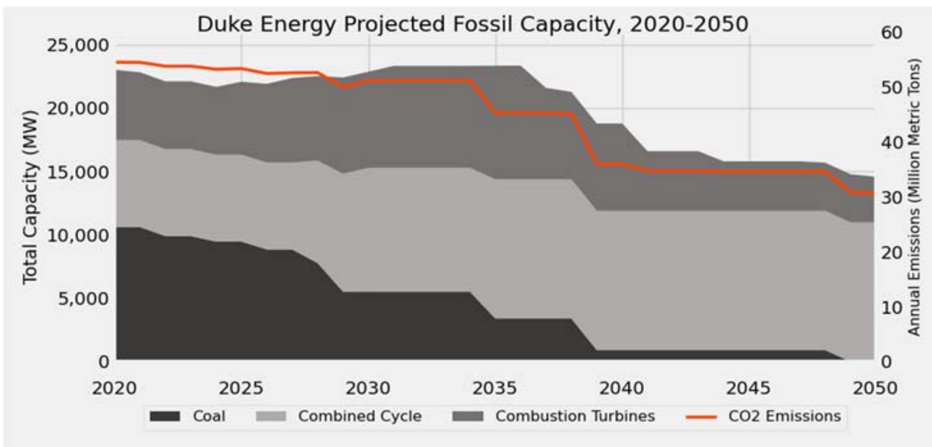

Figure ES-2. *Duke Energy Projected Fossil Capacity and Emissions, 2020-2050. The shaded areas represent operating capacity, in megawatts, of Duke's generation portfolio in the Carolinas (for context, peak coincident load in the Carolinas is approximately 25,000 megawatts[11]). The yellow line projects carbon emissions over time, declining from over 50 million metric tons in 2020 to about 30 million metric tons in 2050. Further explanation is provided in Section D of this report.*

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[8] North Carolina Department of Environmental Quality ("NC DEQ") (2019, October). North Carolina Clean Energy Plan Policy & Action Recommendations. Retrieved at: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[9] Porter, S., Thomson, J., & Motyka, M., (2020, September). Utility decarbonization strategies: Renew, reshape, and refuel to zero. *Deloitte*. Retrieved at: https://www2.deloitte.com/us/en/insights/industry/power-and-utilities/utility-decarbonization-strategies.html.

[10] North Carolina Utilities Commission ("NCUC") (2020, April). Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans. Docket No. E-100, Sub 157. Retrieved at: https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=86f15be3-7617-4910-aeae-d8568c4d0983.

[11] Matsuda-Dunn, R., Emmanuel, M., Chartan, E., Hodge, B., & Brinkman, G., (2020, January). Carbon-Free Resource Integration Study. *National Renewable Energy Laboratory.* Retrieved at: https://www.nrel.gov/docs/fy20osti/74337.pdf.

- **Duke Energy's 2020 Integrated Resource Plans maintain a similar level of carbon-emitting generation capacity through 2035, and much remains online through and past 2050.** While the Integrated Resource Plans contemplate retiring most of the existing coal fleet by 2030, these reductions in fossil capacity are offset by new investment in gas-fired combustion turbines and combined-cycle plants. If the Duke companies continue to operate their fleet as they have historically, the emissions trajectory of Duke Energy's operating companies in the Carolinas will be increasingly inconsistent with Duke Energy's corporate climate commitments. Duke Energy's emissions in the Carolinas will decline about 40 percent by 2050, from 50 million tons of carbon emitted in 2020 to just over 30 million metric tons in 2050. Notably, these totals do not include upstream emissions occurring during methane production and transport. Although the Duke plans include a high-level discussion of carbon-neutral retrofits to their gas-fired assets, including green hydrogen and carbon capture and storage, the IRPs do not include any plans to deploy these technologies or discuss any costs they might incur to ratepayers.

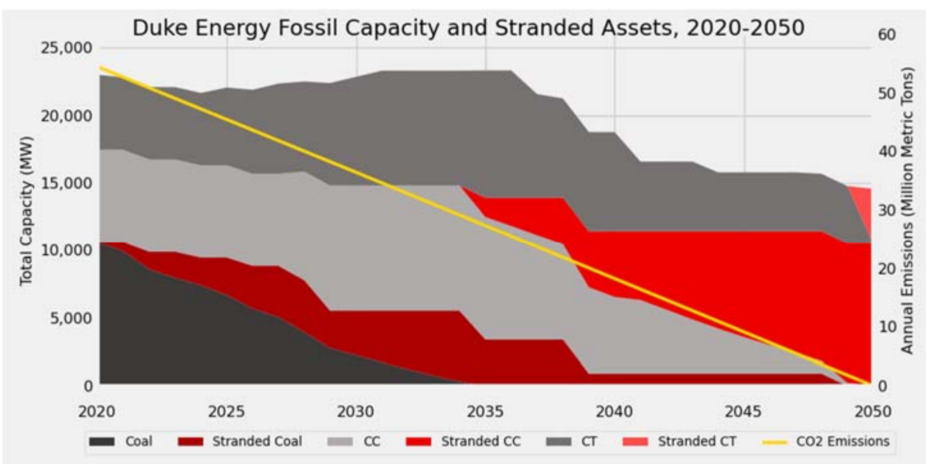

Figure ES-3. *Duke Energy portfolio, with carbon stranded assets to meet climate commitments. In this case, fossil units were removed from operation to comply with Duke Energy's carbon commitments. Black and gray shaded areas represent operating fossil capacity, by technology. Areas shaded red represent units that have been taken offline before the end of their engineering lifetime to meet carbon commitments. The yellow line shows the carbon trajectory of the portfolio, starting at over 50 million metric tons per year and declining toward zero. Further explanation is provided in Section D of this report.*

- **To meet Duke Energy Corporation's corporate climate commitment,** carbon-emitting plants within the Duke Energy fleet in the Carolinas will either need to decrease their usage rate or be pulled out of operation altogether.[12] This includes removing coal entirely from the portfolio in the early 2030s and stranding even recently built combined-cycle plants through the 2030s and 2040s. In this model, combustion turbines are preserved to address resource adequacy concerns and they are allowed to stay online through much of the 2040s (combustion turbines tend to run only during peak demands conditions, and therefore do not contribute as much to total carbon emissions).

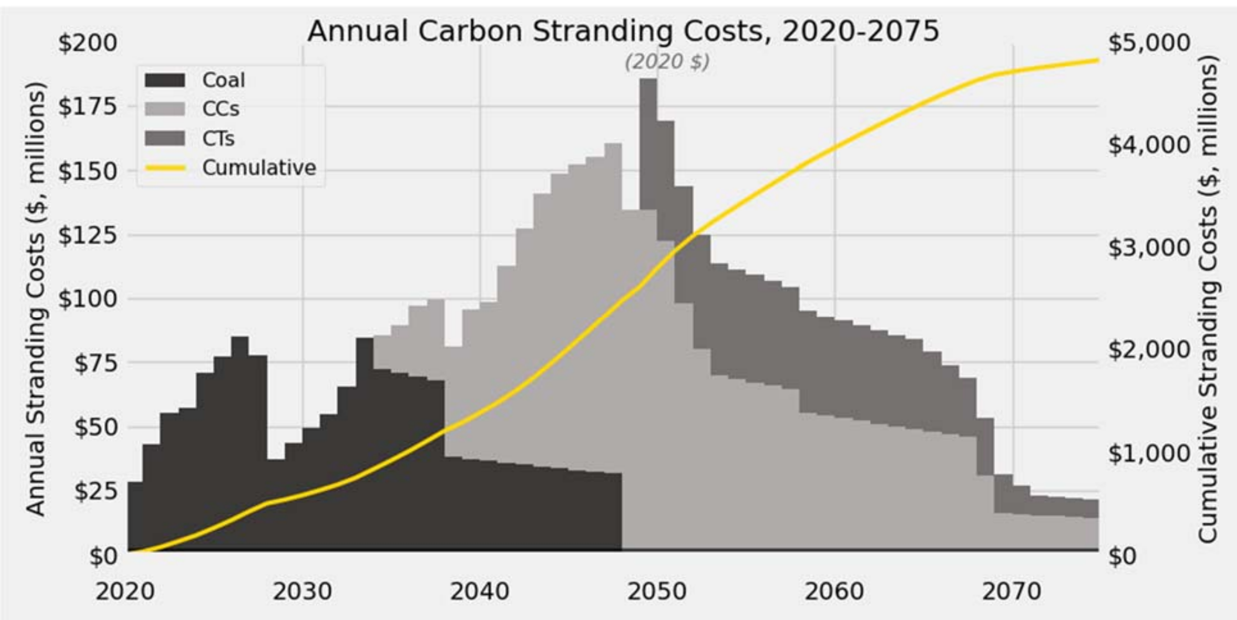

Figure ES-4. *Annual and Cumulative Carbon Stranding Costs, 2020-2075. Bar graphs represent costs of stranded capacity per year, by technology, in millions of dollars. Costs are in the tens of millions through 2030, then increase to as much as $175 million. The yellow line shows cumulative stranded costs, reaching about $4.8 billion. Further explanation is provided in Section D of this report.*

- **These costs are meaningful to ratepayers.** Potential carbon stranding costs to ratepayers are on the order of tens or hundreds of millions of dollars per year. Over the course of these assets'

[12] For the purposes of this analysis, a zero-carbon goal is contemplated rather than a net-zero carbon goal. The availability, costs, and quality of carbon offsets through mid-century are not known; the most certain way to achieve net-zero carbon operations is to achieve gross zero-carbon operations.

lifetimes, ratepayers could pay more than **$4.8 billion** in 2020 dollars for stranded assets. This amount exceeds the total stranded costs to Dominion and Duke Energy combined on the Atlantic Coast Pipeline by more than $1 billion. In present value terms, this is equivalent to a cost of **over $900 per Duke customer in the Carolinas**. Because the planned lifetimes for new power plants often span several decades, cost impacts are incurred through 2074.

Table ES-2. *Key Results of Duke Energy Carbon Stranding Analysis*

Projected GHG Emissions Overshoot in 2050	30 million metric tons
Engineering lifetime of new-build combined-cycle gas plants	40 years
Projected operational lifetime of new-build combined-cycle gas plants	12.3 years
Total Carbon Stranding Costs *(2020 $)*	$4.8 billion
Present-Value Carbon Stranding Costs *(2020 $)*	$3.3 billion
Present-Value Cost per Residential Duke Customer	$916.93

- **Utilities and regulators have tools at their disposal to avoid these costs.** While Duke Energy has begun to incorporate climate risks into its corporate governance, risk assessment can and should be extended downward to the operating company level and be explicitly addressed in integrated resource planning. Similarly, utilities can explicitly integrate corporate carbon commitments into their planning processes. Accordingly, utilities should explicitly discuss end-of-life plans (including accelerated retirement or retrofits for carbon capture) and attendant costs for carbon-emitting assets, even if their actual lifetime is uncertain. Regulators can provide certainty by affirmatively finding that climate-related risks are material and that a consideration of climate-related risks is a necessity for prudent management.

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Introduction

Climate change, and society's response to it, are set to shape the US energy and economic landscape in the 21st century. Major economic and financial institutions are taking note: The US Commodities Future Trading Commission released a groundbreaking report in September 2020 finding that "climate change poses a major risk to the stability of the US financial system and to its ability to sustain the American economy."[13] These trends have caused major banks and asset managers, from JPMorgan Chase[14] to BlackRock,[15] to make commitments to remove climate risk from their portfolio and ensure their portfolios are decarbonizing.

Adjusting to climate change will have deep implications for our electric utilities, a capital-heavy sector responsible for a substantial portion of US carbon emissions and poised to become a linchpin of the zero-carbon economy.[16] Electric utilities are likely to face risks if they are unable or unwilling to decarbonize generation fleets, but the transition to clean energy also holds opportunities: renewable power technologies like wind and solar have continued their unprecedented cost decline, and the International Energy Agency declared in its World Energy Outlook 2020 that solar power had become the "cheapest electricity in history."[17]

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[13] US Commodities Future Trading Commission (2020, September). Managing Climate Risk in the US Financial System. Retrieved at: https://www.cftc.gov/sites/default/files/2020-09/9-9-20%20Report%20of%20the%20Subcommittee%20on%20Climate-Related%20Market%20Risk%20-%20Managing%20Climate%20Risk%20in%20the%20U.S.%20Financial%20System%20for%20posting.pdf.

[14] Benoit, D., (2020, October). "JPMorgan Pledges to Push Clients to Align With Paris Climate Agreement." *Wall Street Journal.* Retrieved at: https://www.wsj.com/articles/jpmorgan-pledges-to-push-clients-to-align-with-paris-climate-agreement-11602018245.

[15] Fink, L. (2020, January). A Fundamental Reshaping of Finance. BlackRock. Retrieved at: https://www.blackrock.com/corporate/investor-relations/larry-fink-ceo-letter.

[16] Mahajan, M., (2019, November). "How To Reach U.S. Net Zero Emissions By 2050: Decarbonizing Electricity." *Forbes.* Retrieved at: https://www.forbes.com/sites/energyinnovation/2019/11/12/how-to-reach-us-net-zero-emissions-by-2050-decarbonizing-electricity/#59f08aa649e7.

[17] Carbon Brief (2020, October). "Solar is now 'cheapest electricity in history', confirms IEA." Retrieved at: https://www.carbonbrief.org/solar-is-now-cheapest-electricity-in-history-confirms-iea.

Like their financers, major US electric utilities have taken note and made bold announcements on their intentions to transition to net-zero carbon energy: between 2018 and 2020, nearly all major US utilities announced a commitment to deeply cutting their emissions to zero or near zero by 2050.[18] But to date, these utilities' investment plans in new fossil generation have not always matched their climate action ambitions. A September 2020 Deloitte study noted that for many utilities, the 'math doesn't yet add up' for utility decarbonization goals,[19] and one watchdog even found that the pace of decarbonization was slated to slow across many utilities in the 2030s.[20]

Duke Energy's 2020 Integrated Resource Plans (IRPs) in the Carolinas present a case study to better understand tensions between corporate climate commitments and short-term investment plans. The 2020 IRPs are Duke Energy's first in the Carolinas since their net-zero-by-2050 commitment, but the plans entail an expansion of fossil-fueled power capacity through the 2030s, rather than a drawdown.

This discrepancy raises deep questions about the nature of the energy transition. What is the relationship between a utility's 30-year commitment to decarbonize and its 15-year integrated resource planning horizon? How should regulators treat corporate climate commitments as they weigh whether the plan is in the public interest? What is the likelihood that these plants are shut down midway through their operational lives (some of which extend into the 2070s)? What are the typical regulatory standards used for allocating these costs, and will they be useful in the context of climate-related changes? These are relevant questions, not only for utilities, their regulators, and advocates, but also for ratepayers and members of the public invested in a climate-resilient economy.

This report explores these questions and assesses how—as a result of Duke's 2020 Carolinas IRPs—ratepayers may be burdened with the fallout from climate-related risks. **Section A** provides background

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[18] Gearino, D., (2020, October). "Inside Clean Energy: Net Zero by 2050 Has Quickly Become the New Normal for the Largest U.S. Utilities." *InsideClimateNews.* Retrieved at: https://insideclimatenews.org/news/30092020/inside-clean-energy-net-zero-2050-utilities.

[19] Deloitte.

[20] Pomerantz, D., (2019, June). Utility Carbon Targets Reflect Decarbonization Slowdown In Crucial Next Decade. Energy and Policy Institute. Retrieved at: https://www.energyandpolicy.org/utility-carbon-targets/.

on the regulatory constructs that determine how utilities plan generation, construct energy prices, and recover money they have invested in long-lived assets. **Section B** explores the multiple dimensions of climate-related risks that affect the electric utility industry in general and Duke Energy's Carolinas footprint in particular. **Section C** provides an overview of Duke Energy's current generation fleet in the Carolinas and the proposals in its 2020 Integrated Resources Plans (IRPs). **Section D** quantifies the potential costs of ratepayers due to "carbon stranded" assets. Finally, **Section E** provides conclusions and policy recommendations.

A. Primer on Utility Generation Planning in the Southeast

The Eastern Interconnection is a connected electricity mega-grid that spans from Key West to Manitoba and has continually provided power to households across the United States since 1967. It is part of the bedrock of modern life in the Eastern half of North America.[21] In fact, the growth of the electricity grid across the United States has been called the single greatest engineering achievement of the 20th century by the National Academy of Engineering.[22] But the modern electricity grid is more than a feat of engineering; it also relies on a complex set of legal, regulatory, and economic relationships and incentives that ensure decisions made on the electricity grid serve the public interest. The plants, poles, and wires are of critical importance, but regulatory and financial dynamics determine when, where, and how they are built. As our electricity grid undergoes transformative changes in the 21st century, from an influx of digital information to the paradigm-shifting impacts of climate change, regulatory institutions will play a role in what changes are made and how quickly they unfold. These regulatory-economic agreements affect the grid at every scale—from the way regions will grow and change, to individual decisions utilities and their regulators make every day. The following section highlights a

[21] Cohn, J. (2019, January). When the Grid Was the Grid: The History of North America's Brief Coast-to-Coast Interconnected Machine. Proceedings of the IEEE. Retrieved at: https://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=8594689.

[22] National Academy of Engineering. Greatest Engineering Achievements of the 20th Century. Retrieved at: http://www.greatachievements.org/.

few terms and concepts that are useful for understanding the incentives and dynamics at play in current resource planning conversations in the Southeast.

i. Electric Utilities, the Regulatory Compact, and the Integrated Resource Plan

The business of making electricity is unique from other parts of the modern economy in two ways. The first is that universal provision of safe, reliable electricity forms the backbone of the modern economy—making it a "public utility."[23] The second is that high barriers to entry and economies of scale have historically rendered the electricity industry a "natural monopoly," although this is changing as distributed energy resources become more widespread.[24] Given that accessible and affordable electricity is in the public interest and, as monopolies, utilities generally do not compete for customers, utility business practices require special attention from the public to ensure that utilities make decisions and set prices in the public interest. Public-sector regulators at public utilities commissions across the country work with utilities to ensure they are managed prudently and in the public interest in what is often called a "regulated monopoly."[25] Regulators use a variety of standards to ensure electricity service is in the public interest; a few include a standard of universal access and an expectation that service and prices be "just and reasonable."[26] If utilities can meet this standard, regulators generally allow the company to receive a reasonable rate of profit on electricity sales. This agreement, wherein utility companies agree to be regulated in the public interest in return for a reasonable opportunity to achieve a return on investment, is called the "regulatory compact."[27] The

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[23] Bonbright, James (1961). Principles of Public Utilities Rates. Columbia University Press. P. 2. Retrieved at: http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

[24] Corneli, S. & Kihm, S. (2015, November). Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future. Lawrence Berkeley National. Laboratory. Retrieved at: https://emp.lbl.gov/publications/electric-industry-structure-and.

[25] Bonbright, p. 22.

[26] Federal Energy Regulatory Commission (2020, July). An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities. Retrieved at: https://www.ferc.gov/sites/default/files/2020-07/ferc101.pdf.

[27] Lazar, J., (2016, June). Electricity Regulation in the US: A Guide. Regulatory Assistance Project. Retrieved at: https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf. P. 6. Lazar notes

compact places pursuit of the public interest at the center of the electric utility business model: a chance at a reasonable rate of profit is dependent on the utility's ability to pursue the public good.

While the general outlines of the regulatory compact are similar across the country, regulation of electric utilities occurs at the state level. States each appoint or elect a commission of public officials (called a public utilities commission or a public service commission) to regulate utilities in their jurisdiction.

Physically, the operation of the electric grid can be divided into distinct segments: ***generation*** describes where and how electrical energy is generated; ***transmission*** describes how electrical energy is transported from where it is created to where it is needed; and ***distribution*** describes how energy is brought to an appropriate voltage and distributed to customers. The purpose of each segment is distinct, but they need to operate in careful synchronization to meet the needs of electricity customers.

For much of the 20th century, electric utilities were 'vertically integrated': the same entities owned and operated all three segments of the grid. Cost overruns and shocks to energy prices during the 1980s, however, challenged the regulatory compact and the vertically integrated model. The existing arrangement did not seem to ensure that customers were protected from price shocks in the long run, and long-held assumptions about economies of scale, fuel costs, and growth in demand were shaken.

New policies and structures were proposed to ensure that utilities were taking prudent steps to ensure affordable electricity in the future. In particular, states instituted requirements for transparency and an opportunity for regulators to weigh in on utilities' long-term plans. Most states formally require utilities to submit an ***integrated resource plan***, which lays out utilities' plans for providing sustainable, low-cost energy over the long term.

A map of states that have instituted integrated resource planning requirements is provided in Figure A-1.

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that the regulatory compact is not a discrete contract or document that represents the regulatory compact, but that it is an "implied agreement."

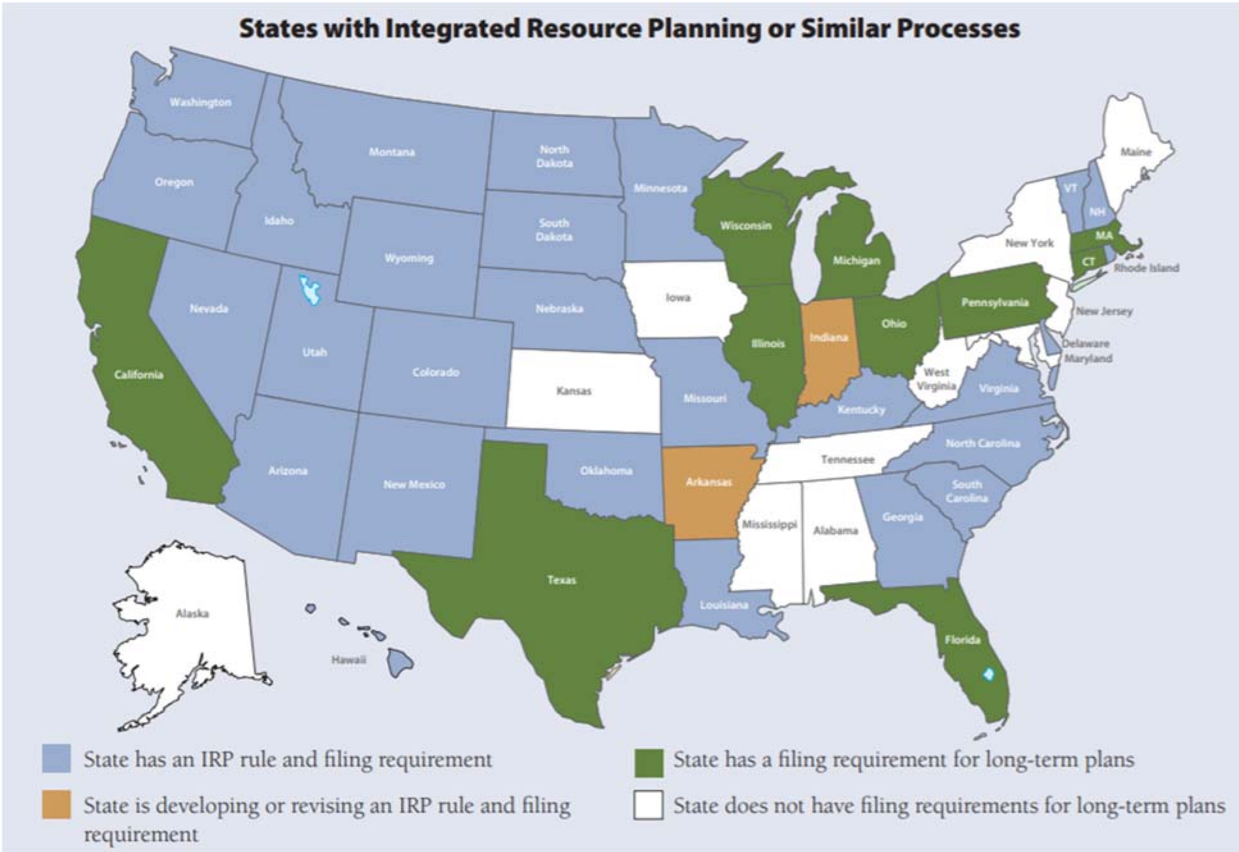

Figure A-1. *States with Integrated Resource Planning or Similar Processes.*[28]

IRPs include projections for future energy needs, an inventory of resources currently available, and plans to construct new power plants to meet anticipated needs. Regulators typically have an opportunity to review and approve, reject, or revise these plans before they are put into effect. A transparent and robust integrated resource planning process between utilities, regulators and advocates ensures not only that current utility practices are in the public interest, but that the utility is prudently laying the groundwork to continue to provide sustainable, affordable power for decades to come.

[28] Wilson, R., & Biewald, B. (2013, June). Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project and Synapse Energy Economics. Retrieved at: https://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf.

ii. Accounting for Generation Investments: Revenue Requirement and Depreciation

The regulatory compact ensures that as long as utilities are acting in the public interest, they are allowed to charge customers for the cost of service, plus an opportunity to receive a fair rate of return on their investments. Of course, provision of electric power is only in the public interest to the extent that it is affordable. This section describes how the investments envisioned in the integrated resource plan are eventually incorporated into everyday utility prices. Several concepts from utility cost accounting are introduced below, including the revenue requirement, rate base, and depreciation.

The first step in determining the appropriate amount to charge customers is determining the total cost of providing electricity over the course of a given year. This annual sum is called the ***revenue requirement*** because it represents the amount of revenue the utility needs to take in in order to pay off all its costs. The revenue requirement includes all costs incurred by utility, from executive compensation to fuel costs and income taxes. The total amount of the revenue requirement is the fundamental driver of the price of electricity, as shown in the equation below.

$$\frac{Revenue\ requirement\ (\$)}{Total\ electricity\ sold\ (kilowatt-hours)} = Average\ price\ of\ electricity\ (\$/kilowatt-hour)$$

Equation A-1. *Relationship of revenue requirement to average price of electricity.*

The revenue requirement must also account for the actual equipment that the utility invests in that make up the physical grid, from power plants to distribution poles. In accounting terms, these pieces of equipment are called ***assets*** and the total value of these investments is called the utility's ***rate base***. A utility's assets add to the revenue requirement in two ways. First, in keeping with the regulatory compact, the utility is allowed an opportunity to earn a profit off of its investments. A set profit margin from the utility's investment in grid equipment, called a return on investment, is included in the revenue requirement (importantly, this means that a utility's profit margin is directly related to the size of its rate base). Second, the revenue requirement also includes the costs of wear and tear on the utility's equipment and assets as they operate over the course of the year. This wear and tear is called

depreciation on the utility's accounting statements. It is represented as a cost to the utility as the value of its assets decreases due to wear and tear.

By accounting for depreciation, utilities ensure they have the funds they need to rebuild new assets as others wear away. An example might be helpful here. A hypothetical transformer has an expected operating lifetime of fifty years, which means after fifty years of operation it will need to be replaced with a brand-new transformer to continue safe and reliable service. In order to raise the money to replace the transformer in fifty years, the utility needs to increase the total amount it charges customers every year (the 'revenue requirement') by a small amount, to build funds to replace the transformer. After fifty years of wear and tear and depreciation costs, the transformer is ready for retirement and the utility has accumulated enough revenue over the years to purchase and install a replacement.

Utilities record return and depreciation for all assets they own, from distribution transformers to transmission lines and large power plants. As a result, depreciation represents a substantial part of the total revenue requirement. When Duke Energy's operating companies in the Carolinas submitted a proposal to increase electricity rates in North Carolina last year, the companies' estimated depreciation costs totaled $2.3 billion in 2018, or 22 percent of the utilities' overall expenses. It is the fourth largest category of costs, after fuel costs, operations & maintenance, and the utility's profit margin. Depreciation costs are also as long-lived as the assets they track—up to half a century or more, depending on the piece of equipment. As a result, it is of critical importance to regulators, utility management, and ratepayers that utilities exercise caution and prudent judgment when considering investment in new, capital-intensive power generation.

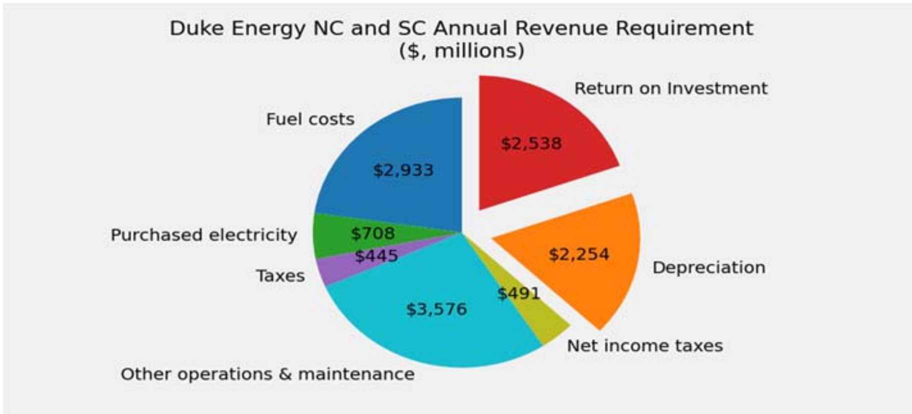

Figure A-2*. Duke Energy Revenue Accounting for Duke Energy Carolinas and Duke Energy Progress in 2018*[29]

iii. Investments in the Public Interest: The 'Used and Useful' Standard and Stranded Asset Risk

To fulfill their end of the regulatory compact, regulators carefully review the revenue requirement, and the depreciating investments included, to determine if it is in the public interest. These regulators must strike a careful balance: If the revenue requirement is too low, utilities might not be able to recover enough revenue to replace key equipment and pay off debts. But because investor-owned utilities have an obligation to shareholders and the return on investment is dependent on how much utilities invest in grid equipment, utilities also have a bias toward investing in new equipment and therefore increasing their revenue requirement.[30] To ensure the revenue requirement is just and reasonable, regulators need to assess which investments are made in the public interest and which are not. This section describes the toolkit available to regulators to ensure investments are in the public interest and explores how that toolkit is used in practice.

[29] Duke Energy Carolinas, LLC (2019, October). Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets. NCUC Docket No: E-7, Sub 1214. P. 238. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=d9326636-e0f5-481e-8691-ce4362fd96d2.; *and*
Duke Energy Progress, LLC (2019, October). Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets. NCUC Docket No: E-2, Sub 1219. P. 279. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=e84103e3-d5a6-4526-9b27-76fcee8764c8.

[30] Shipley, J., (2018, January). Traditional Economic Regulation of Electric Utilities. Regulatory Assistance Project. Retrieved at: https://www.raponline.org/wp-content/uploads/2018/12/rap_shipley_pucs_regulation_overview_2018_dec_17.pdf.

To ensure only investments in the public interest are included in the rate base and revenue requirement, regulators employ a two-part test. In order to receive profit for any asset that a utility invests funds into, the utility must demonstrate that a) the asset is actually being used during the grid's operation; and b) that the asset's use was necessary for prudent grid operations. This test is referred to as the ***used and useful standard.***[31] Assets can fail to qualify as 'used and useful' for several reasons. The clearest example is that of a piece of equipment that is purchased or constructed but is never actually put into operation. Increasingly, legacy fossil-fueled assets are facing risks of losing their used and useful status simply because low-cost renewables can provide the same service at a lower cost.[32] Even if a piece of equipment passes the used and useful standard immediately after it was built, it must continually be used and useful to stay in the rate base and contribute to the utility's revenue requirement.

When assets fail to meet the used and useful standard, their depreciation costs and return on investment are removed from the revenue requirement and the utility's total revenues decrease. In order for depreciation costs and returns to be reintroduced to the revenue requirement, the utility must demonstrate that the asset has returned to 'used and useful' status. When assets have no plausible pathway toward becoming used and useful, they may not result in any additional revenue for the utility and thus create a shortfall: The utility has invested funds in an asset, but has no way to derive revenue from it. In financial terms, these investments are called ***stranded assets***.[33]

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[31] Bilich, A., Colvin, M., & O'Connor, T., (2020). Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California. Environmental Defense Fund. P. 11. Retrieved at: https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

[32] *See* Gimon, E., O'Boyle, M., Clack, C., & McKee, S., (2019, March). The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources. *Energy Innovation*. Retrieved at: https://energyinnovation.org/wp-content/uploads/2019/04/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL2.pdf; *or* Teplin, C., Dyson, S., Engel, A,. Glazer, G., (2019). The Growing Market for Clean Energy Portfolios. *Rocky Mountain Institute.* Retrieved at: https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants/.

[33] Sen, S. (2020, March). Climate policy, stranded assets, and investors' expectations. *Journal of Environmental Economics and Management.* Retrieved at: https://www.sciencedirect.com/science/article/pii/S0095069618307083.

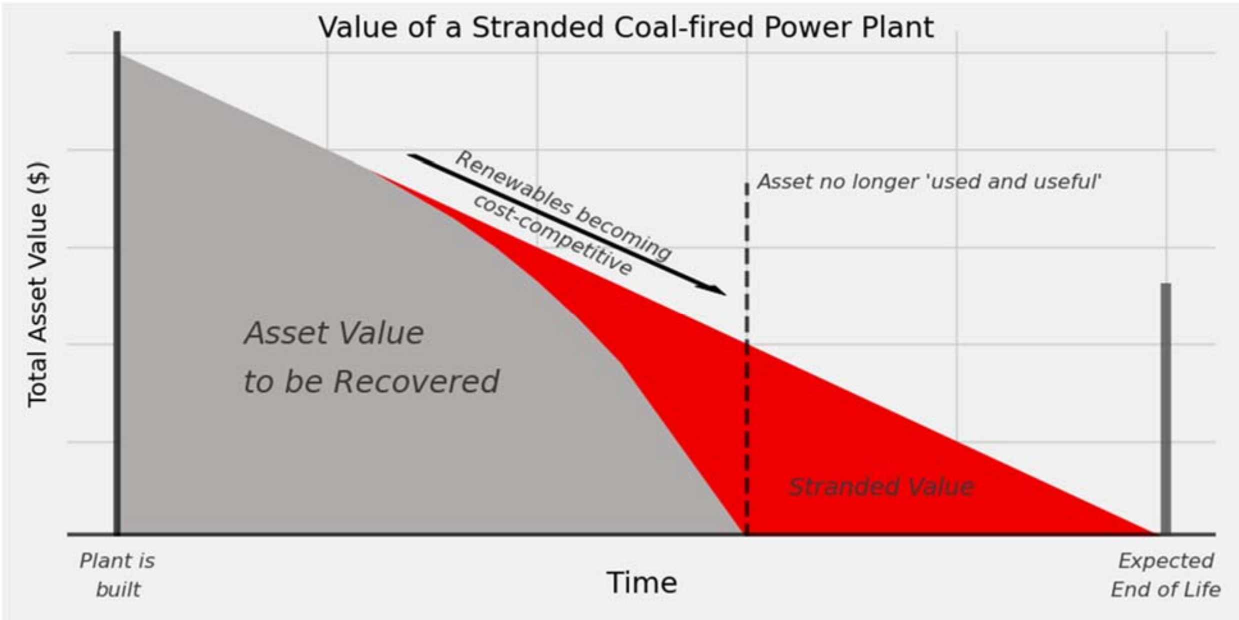

Figure A-3. *Diagram of stranded value of a hypothetical coal-fired power plant*[34]

The diagram above represents a hypothetical coal-fired power plant that is facing pressure from low-cost renewable generation. When it was built, the power plant was expected to maintain its used and useful status for several decades, far into the 21st century. However, as carbon constraints changed the project's economics and renewables plus storage become more cost-competitive, the utility chooses to run the coal plant less frequently because less expensive options are available. Eventually, the coal plant ceases to be used for power generation at all because of complete substitution by more cost-competitive options, thereby failing the 'used and useful' standard. To demonstrate this phenomenon, the coal asset value over time is plotted in Figure A-3. The y-axis represents the total asset value of the plant, and the x-axis represents the passage of time. Over time, the asset's value decreases due to depreciation. But as utilities generate electricity from more economic options, the coal plant becomes less and less 'useful.' When the coal plant is no longer used to generate electricity, it fails to meet the used and useful standard. The area shaded in red, representing expected value from the asset that is never realized, is the 'stranded' value.

[34] *Image inspired by:* Bilich, A, *et al.*, p. 17.

Theoretically, the 'used and useful' standard is a powerful tool for regulators to ensure that utilities operate efficiently and ratepayer costs remain low. In practice, however, the standard is difficult to implement. Regulators operate with less information at their disposal than utility companies,[35] and, as described above, utilities are incentivized to include as much capital as possible in their rate base. As a result, utilities have historically enjoyed the presumption from regulators that their investments are used and useful, instead of a strict burden of proof.[36]

In some cases, the relative hurdle for utilities to prove the used and useful nature of their assets has shifted even further. Utilities have (often successfully) argued that even if a given asset ceases to be used and useful, the utility should be able to continue to receive payment because it *appeared* to be a prudent investment at the time it was built. Although this was not the original intention of the standard, the effectiveness of the used and useful test has been substantially diminished by overriding concerns about the financial health of the utility.[37]

Utility executives and financial observers have adapted to the weakened implementation of this standard. In a 2018 report on stranded asset recovery, Moody's Investor Service found that "In almost all cases, the utilities were able to recover stranded costs without hurting their credit quality."[38] Another survey of investors in the power generation sector found that investors "take stranded asset risk into consideration, but that they also expect a financial compensation for their stranded assets."[39] In this environment, utilities might be emboldened to make risky, carbon-intensive capital investments, given a higher level of confidence that they will avoid penalties if the asset ceases to be

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[35] Ozar, R., (2017, November). Incentive Regulation of Distribution Utilities, A Primer: Theory and Practice. Retrieved at: https://www.michigan.gov/documents/mpsc/Appendix_H_609239_7.pdf.

[36] Lazar, p. 52.

[37] Hoecker, J. (1987). "Used and Useful" : Autopsy of a Ratemaking Policy. Retrieved at: https://www.eba-net.org/assets/1/6/25_8EnergyLJ303(1987).pdf.

[38] T&D World, (2018, November). "Stranded Asset Risk is Low for U.S.-Regulated Utilities as They Shift To Renewable Energy." Retrieved at: https://www.tdworld.com/grid-innovations/generation-and-renewables/article/20971907/stranded-asset-risk-is-low-for-usregulated-utilities-as-they-shift-to-renewable-energy.

[39] Sen.

used and useful. As the electricity grid undergoes a transformation in the 21st century, utility executives are maintaining their confidence in asset recovery; less than twenty percent of utility executives believe that stranded generation assets are a major risk through the energy transition.[40] The potential consequence of this stance toward stranded assets is that utilities may charge their ratepayers for investments and equipment that are not providing value to the system, even when such risks are foreseeable. While there is more certainty for utility executives and shareholders, ratepayers bear the burden of stranded asset costs.

The evolution of the used and useful standard represents a gap in public oversight and a shift of risk from utilities to ratepayers. If a utility makes investments that do not ultimately prove useful, are hindered by long-anticipated regulation, or are outcompeted by new technologies, utility ownership would bear the costs under the traditional used and useful standard. Under the commonly practiced implementation of the standard, though, utilities could still earn a return on those investments, creating an obligation for ratepayers to pay off those investments. In the context of modern integrated resource planning, where utilities are investing in long-lived technologies in a rapidly changing economic, regulatory, and technological environment, ratepayers face substantial exposure to paying off assets that are ultimately not useful, while utilities shareholders are insulated.

B. Climate Risk's Disruptive Impact on Utility Planning

Institutions like the regulatory compact, the used and useful standard, and cost-of-service ratemaking have guided the electricity industry since the 1800s, but the regulatory system will face new challenges in the 21st century. The onset of climate change is applying new shocks and stresses to legacy utility assets—a phenomenon most clearly seen in the wildfires started by utility equipment (and eventually

[40] Morehouse, C., (2020, February). "Utilities don't see stranded assets as a top risk. Should they?" *Utility Dive*. Retrieved at: https://www.utilitydive.com/news/utilities-dont-see-stranded-assets-as-a-top-risk-should-they/572246/.

bankrupting Pacific Gas & Electric) in California's 2018 wildfire season.[41] It has also galvanized a market, social, regulatory and economic response that is transforming the industry. Renewable energy resources, like solar and wind energy, have become a least-cost power resource and are displacing legacy fossil generation across the country.[42] Energy storage, long assumed to be too expensive to be deployed at scale, is appearing *en masse* across the grid.[43] Local and state policymakers have increased their ambition again and again with legislative and executive actions guiding the country toward a decarbonized power system.[44] At the same time, these actions are unfolding while the grid is becoming increasingly digital and more information is available than ever.[45] As utilities and their regulators plan for the future, they must do so while the ground is quickly shifting underneath their feet, using tools that were designed in a different era.

Beyond electricity, climate risks and opportunities are transforming the whole economic landscape, and central institutions are responding. Economic and financial leaders from the Federal Reserve, G20's Financial Stability Board, and BlackRock CEO Larry Fink are preparing for transformative shifts across the economy. The need for a common language on climate impacts led the G20's Financial Stability Board to create the Task Force on Climate-Related Financial Disclosures (TCFD). The TCFD's standards and recommendations, adopted by over 800 organizations representing over $118 trillion in

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[41] MacWilliams, J., La Monaca, S., & Kobus, J., (2019, August). PG&E: Market and Policy Perspectives on the First Climate Change Bankruptcy. Columbia Global Energy Program. Retrieved at: https://energypolicy.columbia.edu/sites/default/files/file-uploads/PG&E-CGEP_Report_081519-2.pdf.

[42] Teplin *et al.*

[43] Wood Mackenzie, (2020, December). U.S. Energy Storage Monitor. Retrieved at: https://www.woodmac.com/research/products/power-and-renewables/us-energy-storage-monitor/.

[44] Micek, K., (2020, August). Analysis: States' renewable mandates continue to grow; nine set 100% clean energy goals. S&P Global. Retrieved at: https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081420-states-renewable-mandates-continue-to-grow-nine-set-100-clean-energy-goals.

[45] St. John, Jeff., (2020, August). 5 Grid Edge Mega Trends in 2020. *GreenTechMedia.* Retrieved at: https://www.greentechmedia.com/squared/dispatches-from-the-grid-edge/5-grid-edge-mega-trends-in-2020.

assets, have become the international standard for discussing the financial and economic impacts of climate change.[46]

Key to the TCFD's definition of climate risk is an acknowledgement that the risks and opportunities arising from climate change originate not just in the change in physical phenomena, but also the collective societal and economic response to mitigate and adapt to climate change. The TCFD calls the risks and opportunities caused by the social & economic response to climate change 'transition risks' and categorizes them into financial, regulatory, economic, and reputational risks. Understanding those risks as separate from but linked to the physical risks is necessary for a complete view of the financial and economic impacts of climate change.

The utility sector's expensive, long-lived and immobile assets, combined with its historical reliance on fossil fuels and attendant greenhouse gas emissions, create a special sensitivity to these risks.[47] Utilities will need to anticipate and adapt to these risks and opportunities, and traditional regulation and planning concepts will need to adjust to reflect this reality and continue to serve the public interest.[48]

Duke Energy and its companies in the Carolinas are on the leading edge of these climate transformations. As a state in the Sun Belt, North Carolina has a solid solar resource and is second only to California in total deployment of solar energy.[49] At the same time, the state is grappling with its increased vulnerability to climate-related risks like amplified hurricanes and sea level rise. Those factors led Governor Roy Cooper to sign Executive Order 80 in 2018, which is paving a path for a climate-

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[46] Task Force on Climate-Related Financial Disclosures ("TCFD") (2019, June). Task Force on Climate-related Financial Disclosures: Status Report. Retrieved at: https://assets.bbhub.io/company/sites/60/2020/10/2019-TCFD-Status-Report-FINAL-0531191.pdf.

[47] TCFD.

[48] Gimon, E., (2020, April). Why Climate Advocates Should be Interested in Resource Adequacy. Energy Innovation. Retrieved at: https://energyinnovation.org/wp-content/uploads/2020/04/Why-Climate-Advocates-Should-Be-Interested-In-Resource-Adequacy.pdf.

[49] Solar Energy Industries Association (2020). North Carolina Solar. Retrieved at: https://www.seia.org/state-solar-policy/north-carolina-solar.

resilient state.[50] Duke Energy will need to play a major part in the transition in the Carolinas; it covers the lion's share of retail electricity in North and South Carolina, and its nationwide footprint of utility companies represents the highest total greenhouse gas emissions among power producers in the country.[51] Duke Energy's footprint in the Carolinas therefore represents a fitting case study for understanding the emerging risks and opportunities from climate change. Each of the risk categories identified by the TCFD is presented below, with a brief description of risk exposure to Duke's portfolio in the Carolinas and implications for utility planning in the future.

i. Physical Risks: Assets at risk of damage from climate-fueled exposure

Physical risks describe the ways that climate-related physical phenomena, like rising sea levels, more intense storms, heat waves, or more frequent flooding could impair grid operations and damage or otherwise devalue utility assets. Understanding the risks to the economy in the Carolinas broadly, the North Carolina Department of Environmental Quality commissioned a Climate Science Report to understand the incidence of climate-related phenomena. The report found that "it is ***very likely*** that extreme precipitation frequency and intensity in North Carolina will increase," and "heavy precipitation accompanying hurricanes that pass near or over North Carolina is ***very likely*** to increase" [emphasis original].[52] Utility-specific analysis has also found a relatively high level of risk in the Carolinas. A report commissioned by Moody's analytics and authored by leading climate analytics firm Four Twenty Seven found that Duke is among the most at-risk utilities due to the changing climate, specifically pointing out hurricane threats.[53]

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[50] State of North Carolina (2018, October). Executive Order No. 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy. Retrieved at: https://files.nc.gov/governor/documents/files/EO80-%20NC%27s%20Commitment%20to%20Address%20Climate%20Change%20%26%20Transition%20to%20a%20Clean%20Energy%20Economy.pdf.

[51] Ceres (2020, May). Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States. Retrieved at: https://www.ceres.org/sites/default/files/reports/2020-07/Air%20Emissions%20Benchmark%202020.pdf.

[52] Kunkel *et al.*

[53] Morehouse.

To address a changing physical environment, utility planners and regulators will need to suspend an assumption that historical average environmental conditions are an appropriate approximation of present and future conditions. When Con Edison conducted a comprehensive study of climate impacts on the assets and operations of its system, the utility found its "systems are all vulnerable to increased flooding and coastal storms; … [and] increasing temperatures; and the electric system is also vulnerable to heat events."[54] While ConEd's study focused on distribution systems, the same dynamics also apply to generation planning, from identifying concerns to engineering design standards.

ii. Financial Risks: Growing interest in Environmental, Social, & Governance (ESG) Issues

Financial institutions have been on the leading edge of calling for more analysis of the economic risks of climate change, and financial actors are now beginning to act on that analysis and entities' mitigation plans. BlackRock, the third-largest shareholder in Duke Energy stock, is leading a reassessment of climate risks among financers. BlackRock CEO sent a letter to CEOs in January 2020 stating that climate change was driving a "fundamental reshaping of finance."[55] Over 2019 and 2020, BlackRock voted against boards of directors 55 times due to lack of progress on mitigating climate impacts.[56] The United States Commodity Futures Trading Commission released a report and recommendations on climate risk to the US financial system in September 2020, and one Commissioner concluded that managing climate risk "isn't someone else's job.'[57] Electric utilities like Duke will need to adequately characterize their level of climate risk, and prudently move to mitigate that risk, in order to maintain their level of financial health. Duke Energy's companies mention in

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[54] Con Edison (2019, December). Climate Change Vulnerability Study. Retrieved at: https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf?la=en.

[55] Fink.

[56] Partridge.

[57] Ellfeldt, A., (2020, September). "Regulator: Climate risk isn't 'someone else's job.'" *E&E News ClimateWire.* Retrieved at: https://www.eenews.net/climatewire/2020/09/21/stories/1063714225.

their most recent Carolinas IRPs that they are also facing interest from investors focused on environmental, social, and governance (ESG) issues.[58]

The standard for integrated resource planning is typically a 'least-cost' approach, where utility planners and regulators optimize to meet necessary demand for power at least cost to consumers.[59] The advent of climate-related risks and financial oversight complicates this standard. A given resource plan that results in least-cost short term, for example, may lead to higher financing costs over the long term because of its treatment of climate risks. Utility planners and regulators should be aware of this dynamic when deciding which resource plan is truly cost-optimal.

iii. Economic Risks: Pressure from Low-cost Renewables

Renewable energy technologies, bolstered by supportive policy and early adoption by jurisdictions with ambitious climate policy, have become economically competitive with conventional generation, even on a no-subsidy basis.[60] These new resources, with zero ongoing costs for fuel, are already transforming the energy mix across the country. These conditions led competitive energy supplier Vistra to announce that it would retire 6,800 megawatts of coal capacity in the Midwest by 2027.[61] When experts from the Rocky Mountain Institute assessed the cost of replacing gas generation, hour-for-hour, with zero-carbon energy resources, they found that 90 percent of new proposed gas plants could be cost-effectively substituted with clean energy resources—and that by the mid-2020s, even existing gas plants could be outcompeted by new-build clean energy resources.[62] Analysis from Bloomberg New Energy Finance found the same result, noting that hybrid solar-plus-storage assets

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[58] DEC IRP Report, p. 93.

[59] This standard is often directly written into statutes regarding Integrated Resource Plans; See N.C. G. S. § 62-2(3a);

[60] Lazard.

[61] Morehouse, C., (2020, September). "Vistra to retire 6.8 GW coal, blaming 'irreparably dysfunctional MISO market.'" *UtilityDive*. Retrieved at: https://www.utilitydive.com/news/vistra-retire-68-gw-coal-blames-irreparably-dysfunctional-miso-market/586113/.

[62] Teplin *et al.*

"represent a zero-emissions threat to gas," and "undermine the case for many proposed new-build gas power plants, and dramatically change the generation profiles and economics of others."[63]

Experts and analysis are finding the same result in the Southeast. Analysts at Vibrant Clean Energy have found that all coal plants in the Carolinas would be outcompeted by wind and solar by 2025,[64] and a study sponsored by the University of California at Berkeley shows that the Carolinas could get to 90 percent clean energy by 2035—without an overall increase in energy prices.[65] If utilities in the Southeast pooled their resources across utility lines, they could integrate far more renewable resources—at a lower cost to ratepayers.[66]

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[63] BloombergNEF, (2020, November). How PV-Plus-Storage Will Compete With Gas Generation in the US. Retrieved at: https://assets.bbhub.io/professional/sites/24/BloombergNEF-How-PV-Plus-Storage-Will-Compete-With-Gas-Generation-in-the-U.S.-Nov-2020.pdf.

[64] Gimon, E., O'Boyle, M., McNair, T., Clack, C., Choukulkar, A., Cote, B., & McKee, S., (2020, August). Summary Report: Economic and Clean Energy Benefits of Establishing a Southeast U.S. Competitive Wholesale Electricity Market. *EnergyInnovation and Vibrant Clean Energy.* Retrieved at: https://energyinnovation.org/wp-content/uploads/2020/08/Economic-And-Clean-Energy-Benefits-Of-Establishing-A-Southeast-U.S.-Competitive-Wholesale-Electricity-Market_FINAL.pdf.

[65] Phadke, A., Paliwa, U., Abhyankar, N., McNair, T., Paulos, B., Wooley, D., O'Connell, R., (2020, June). 2035 Report: Plummeting Solar, Wind, and Battery Costs can Accelerate our Clean Electricity Future. Retrieved at: http://www.2035report.com/wp-content/uploads/2020/06/2035-Report.pdf?utm_referrer=https%3A%2F%2Fwww.2035report.com%2F.

[66] Gimon *et al.*

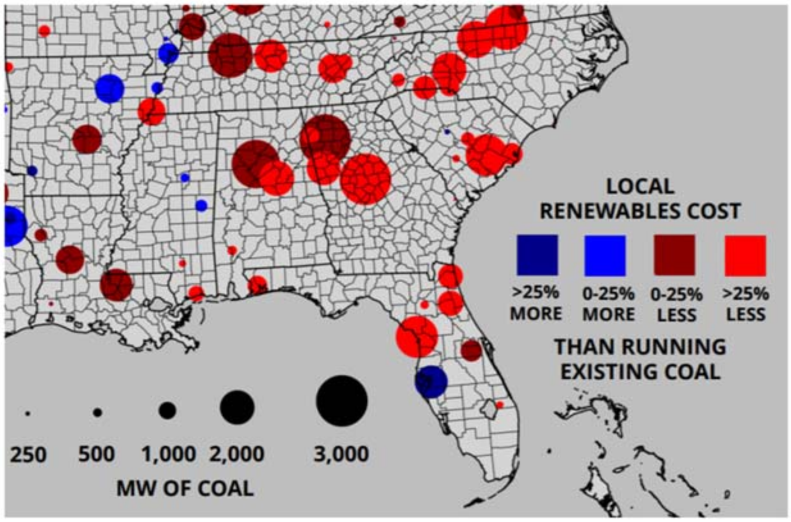

Figure B-1. *Comparison of coal operating costs versus local renewables in the Southeast*[67]

For utilities and their ratepayers to take advantage of these economic opportunities and avoid the economic risks, generation planning processes must ensure that they are able to fully capture the value of variable and flexible resources. Traditional notions of cheap, inflexible 'baseload' resources versus more expensive 'peaker' resources do not apply cleanly to variable, low-cost resources like wind and solar or flexible, dispatchable resources like aggregated demand response or energy storage. To address this new reality, expert analysts have advocated for a more holistic view of generation capacity planning.[68] These dynamics contributed to the North Carolina Utilities Commission's request that Duke's companies not treat conventional reserve margin planning as a "hard and fast" rule:

> Prudent investments in additional generating capacity in the short term must take [risk of stranding from renewable resources] into account, and an absolute insistence on a single fixed and unvarying planning reserve margin does not … permit sufficient flexibility to do so.[69]

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[67] Gimon, E., O'Boyle, M., Clack, C., McKee, S,. (2019, March). The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources. Vibrant Clean Energy and Energy Innovation. Retrieved at: https://energyinnovation.org/wp-content/uploads/2019/04/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL2.pdf.

[68] Gimon.

[69] North Carolina Utilities Commission ("NCUC"), (2020, April). Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans. Docket No. E-100, Sub 157. P. 11. Retrieved at: https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=86f15be3-7617-4910-aeae-d8568c4d0983.

iv. Regulatory Risks: Carbon Prices & Clean Energy Standards

Regulatory climate-related risks in the utility sector represent risks to assets, net revenues, and operations by carbon or clean energy regulation at the state or federal level. Examples of policies that could cause regulatory costs include a price on carbon or a clean energy standard. In its most recent Carolinas IRPs, Duke Energy discusses several federal regulations that it has been tracking, including the Climate Leadership Council's proposal ($40/ton CO_2, escalating at 5 percent per year) and the American Opportunity Carbon Free Act of 2019 ($52/ton CO_2, escalating at 8.5 percent per year). To account for uncertainty and appropriate market signals, rather than a simple externality price, leading economists have also recently proposed risk-informed carbon prices that begin at a high value, then decline over time.[70]

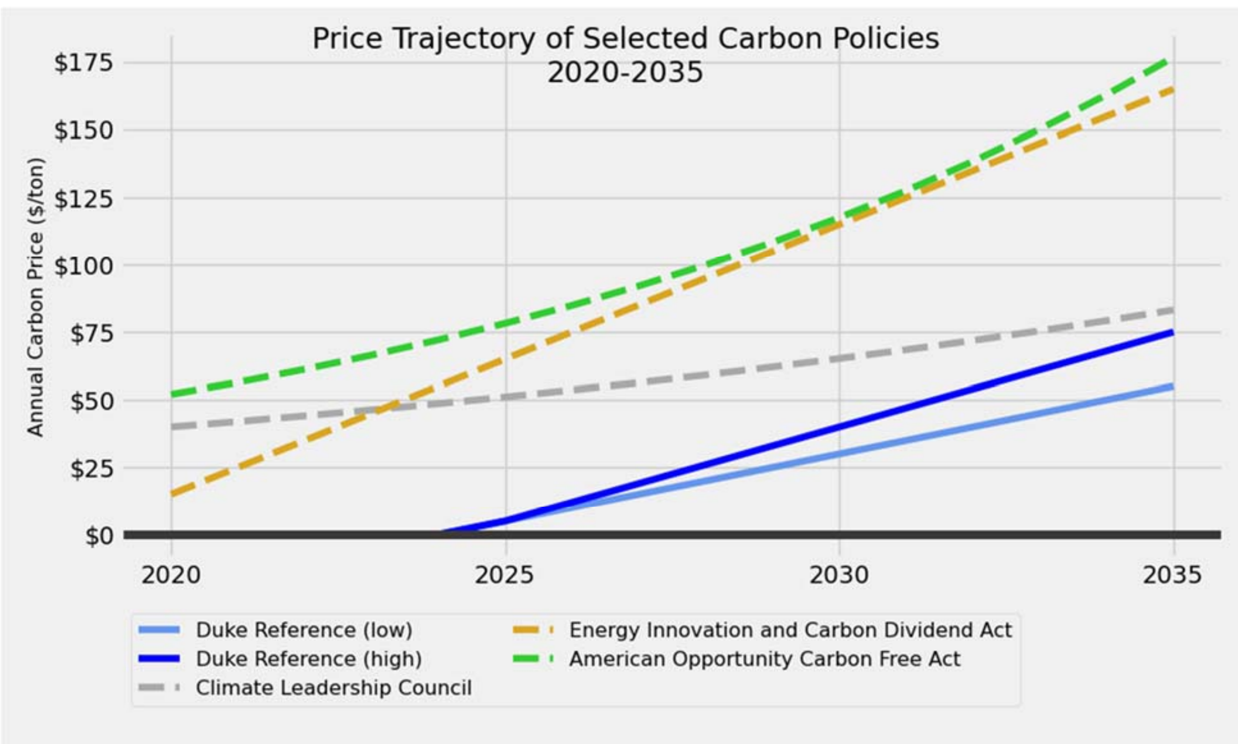

Figure B-2. *Magnitude of potential federal carbon regulation prices, 2020-2035. Plotted with Duke Integrated Resources Plan reference carbon prices. Prices in nominal US dollars.*[71]

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[70] For examples, see Gernot Wagner's EZ-Climate and Noah Kaufman's Near-Term to Net-Zero (NT2NZ).

[71] See DEC IRP Report, p. 152-154.

Incorporating a carbon price or clean energy standard is relatively straightforward in most resource planning processes, and Duke's most recent IRPs in the Carolinas have incorporated an assumed carbon price of $5/ton starting in 2025.

Ambition for state-level climate policy is also rising in the Carolinas. The Clean Energy Plan that emerged from Cooper's Executive Order 80 in 2018 contemplates several potential state-level policy actions,[72] and South Carolina's Energy Freedom Act of 2019 empowers the South Carolina Public Service Commission to consider a broader array of costs and risks when making its determination on whether an integrated resources plan is 'just and reasonable.'[73] The Clean Energy Plan and the Energy Freedom Act are further discussed in Section C.

v. Reputational Risks: Do Utilities' plans line up with their net-zero commitments?

Reputational risks represent the risks to a firm's relationship with customers, regulators, suppliers, and the public due to the business's carbon emissions and its perceived progress on climate change mitigation and adaptation. Utilities that sustain reputational impacts due to their approach to climate risks may find less friendly relationships with regulators, political entities, and financial observers,which could ultimately have substantial effects on the utility's shareholders.

Utilities across the country have managed climate-related reputational risks by announcing commitments or goals to decarbonize their operations by 2050. The announcements could blunt regulators' inclinations to mandate decarbonization measures if there is a sense that utilities are good-faith actors who will decarbonize without the need for close regulation. A list of large utilities and their decarbonization targets is provided below.

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[72] NC DEQ, 2019.

[73] Direct Testimony of Kenneth Sercy on behalf of the South Carolina Solar Business Alliance, Inc. (2020, July). South Carolina Public Service Commission Docket No. 2019-226-E. Retrieved at: https://dms.psc.sc.gov/Attachments/Matter/c6cfec80-c3eb-46f8-b9fd-26b9a76ee9ca.

Table B-1. *Major Utility Carbon Emissions Goals, sorted by announcement date.*[74]

Company	Carbon Commitment	Date Announced
FirstEnergy	90 percent by 2045	December 2015
Xcel Energy	Net zero by 2050	December 2018
Dominion	Net zero by 2050	December 2018
NextEra Energy	40 percent by 2025	June 2019
PSEG	80 percent by 2046	July 2019
DTE Energy	Net zero by 2050	September 2019
AEP	80 percent by 2050	September 2019
Duke Energy	**Net zero by 2050**	**September 2019**
Southern Company	Net zero by 2050	May 2020
Entergy	Net zero by 2050	September 2020
Ameren	Net zero by 2050	September 2020

For utility executives, decarbonization goals could be a double-edged sword. As long as the public perceives that utilities are proactively implementing their climate commitments, decarbonization goals could be a reputational asset. If public perception were to find that utilities were not moving to achieve their carbon goals, then the decarbonization goal could be a liability for the company.

As the number of utilities with decarbonization goals has accumulated, public scrutiny has increased. A September 2020 report from Deloitte concludes that generally, "the math doesn't yet add up" when it comes to utility decarbonization plans.[75] Another report from Synapse found that "utilities appear in some cases to simply be responding to state pressures or requirements rather than demonstrating

[74] Gearino, D.

[75] Porter, et al.

the independent leadership needed to achieve ambitious decarbonization targets."[76] For utilities like Duke to avoid sustaining reputational damage, they need to ensure that public-facing planning presents a credible, good-faith attempt at decarbonization.

vi. Revisiting Stranded Assets in Light of Climate Risks

Traditionally, utility planners and their regulators enjoyed the assumption of consistency. With the exception of total demand for electricity growing slowly year-to-year, utility planners were able to plan years and even decades into the future with a generally reasonable presumption that future conditions would be similar to the present. Climate change's impacts on the utility sector have obliterated that presumption. Utility planners now need to make their decisions in a context where climate-related risks continue to evolve at a rapid pace. There is no question that these risks will continue to develop and emerge: Utilities' common net-zero goal year, 2050, is less than three decades away. Energy infrastructure built today will be well within its operating lifetime through mid-century.

These quickly evolving risks multiply the potential risk for utility investments. Although the categories of climate-related risks have different vectors, each could contribute to a historical investment losing its used-and-useful status, years before expected. Of course, careful, climate-risk-informed planning could also avoid these stranded assets. The North Carolina Utilities Commission acknowledged this dynamic in its March 2020 order::

> The Commission observes that all parties agree that the near and intermediate term periods will be marked by rapid technological change accompanied and reinforced by potentially dramatic changes in the costs of new generating technologies and compounded by an increasing emphasis on reduction in greenhouse gas emissions from electric power generation. The Commission's view is no different. For this reason it is important when applying the principle of long-term least cost planning for generation assets that the Companies avoid near term investments in long-lived

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[76] Biewald, B., Glick, D., Hall, J., Odom, C., Roberto, C., & Wilson, R., (2020, March). Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets. Synapse Energy Economics. Retrieved at: https://www.synapse-energy.com/sites/default/files/Investing-in-Failure-20-005.pdf.

generating assets that may, due to market forces and technological change, become economically stranded over the course of the longer planning period.[77]

The US Commodity Futures Trading Commission (CFTC) puts the sentiment more simply: "In essence, transition risks arise when firms fail to prepare for or recognize broader market transitions. In a speedy transition to a net-zero economy, fossil fuel industry assets might become stranded."[78] The CFTC cites estimates of potential stranded asset cost due to climate-related transition risks up to $4 trillion across the economy. If firms and their financers fail to adequately consider transition risks, CFTC warns, systemic impacts are possible. Given the urgency of central economic actors' messages on climate risk, the transition to proactively managing climate risk is more a question of 'when' than a question of 'if.'

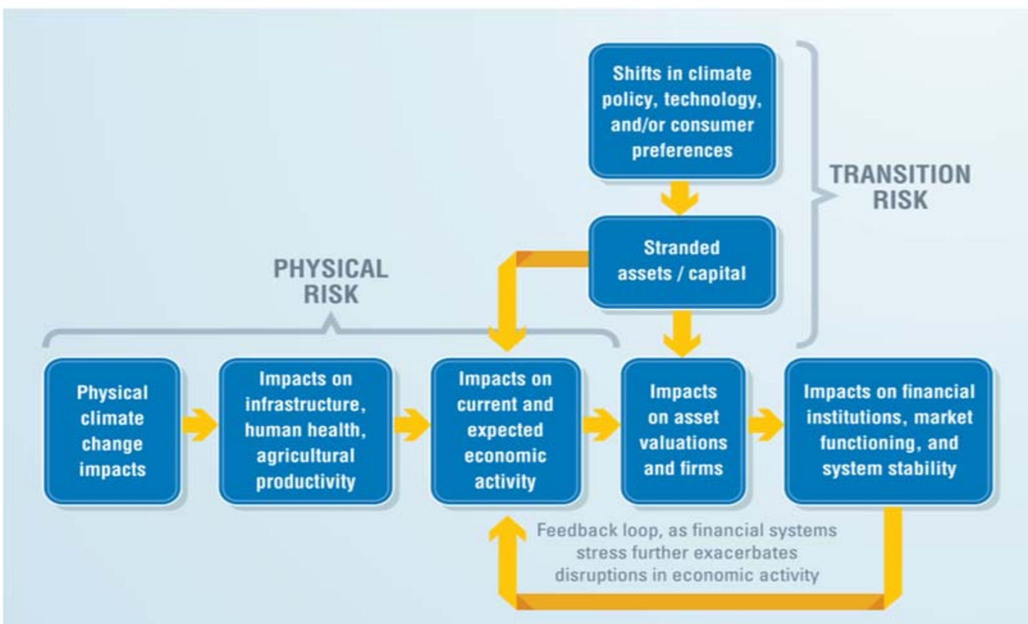

Figure B-3. *Impacts of physical and transition risks on assets, firms, and financial markets. From U.S. Commodity Futures Trading Commission, "Managing Climate Risk in the U.S. Financial System."*[79]

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[77] NCUC.

[78] U.S. Commodity Futures Trading Commission (2020, September). Managing Climate Risk in the U.S. Financial System. P. 19. Retrieved at: https://www.cftc.gov/sites/default/files/2020-09/9-9-20%20Report%20of%20the%20Subcommittee%20on%20Climate-Related%20Market%20Risk%20-%20Managing%20Climate%20Risk%20in%20the%20U.S.%20Financial%20System%20for%20posting.pdf p. 19.

[79] *Ibid.*

While each of the transition risks listed above might impact utility assets and operations through different vectors, they are each capable of impairing operations and causing stranded assets. To simplify the discussion of stranded assets and stranded asset costs due to climate-related transition risks, this concept will be called '***carbon stranding***' throughout this report.

C. Duke's Portfolio and Integrated Resource Plan in the Carolinas

The remainder of this report will apply this understanding of resource planning, stranded assets, climate-related risks, and carbon stranding to Duke Energy's generation portfolio in the Carolinas, with a particular focus on the Duke Energy companies' 2020 Integrated Resource Plans, filed September 1, 2020 with the North Carolina Utilities Commission and the South Carolina Public Service Commission. The report will explore the companies' current portfolio of large power generators, then characterize the specific planned generation investments in the Integrated Resource Plans. Given that these integrated resource plans are Duke Energy's first in the Carolinas after its commitment to net zero carbon by 2050, the report will discuss the compatibility of Duke's preferred portfolio with its climate commitments and emerging climate-related opportunities and risks.

i. Duke Energy Carolinas, Duke Energy Progress, and their Generation Portfolios

Duke Energy is one of the largest energy holding companies in the United States, owning regulated utility subsidiaries that operate in Indiana, Ohio, Kentucky, the Carolinas, and Florida. In addition to its regulated utility companies, Duke Energy also operates a Gas Utilities and Infrastructure unit as well as a competitive Renewables unit. As an aggregated corporation, Duke Energy generates more electricity than any other entity in the United States and emits over 100 million tons of carbon dioxide annually, second only to Vistra Energy in the United States.[80]

[80] Ceres.

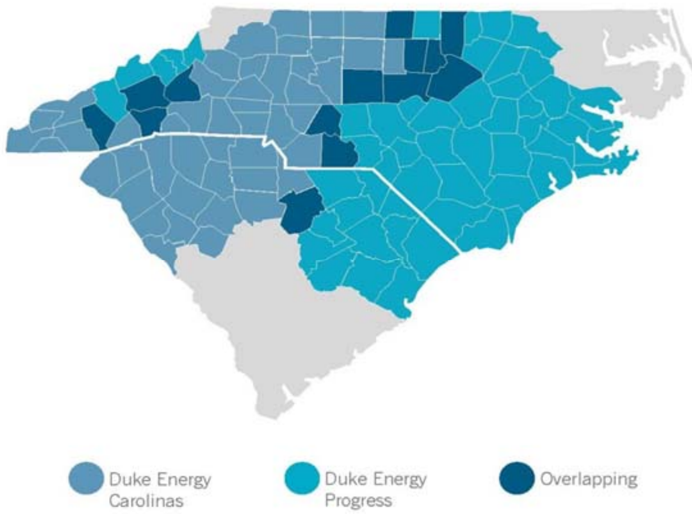

Figure C-1. *Duke Energy Carolinas and Duke Energy Progress service areas.*[81]

In the Carolinas, Duke Energy owns two regulated utility companies, Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP). Duke began operating both companies after a merger with Progress Energy in 2012. The companies are distinct corporate entities, but they coordinate power plant operations to serve load across the companies. They also submit coordinated regulatory proposals across companies, including Integrated Resource Plans. While the DEC and DEP IRPs are distinct, they will be treated as a single document throughout this report, and their generation portfolios will be treated as a single group. However, DEC and DEP fleets are still responsible for meeting resource adequacy standards over their respective footprints.

[81] The Hannon Law Firm (2020). Duke Energy Data Beach Exposed Personal Information of 370,000 Customers. Retrieved at: https://www.hannonlaw.com/blog/duke-energy-data-breach-exposed-personal-information-370000-customers/.

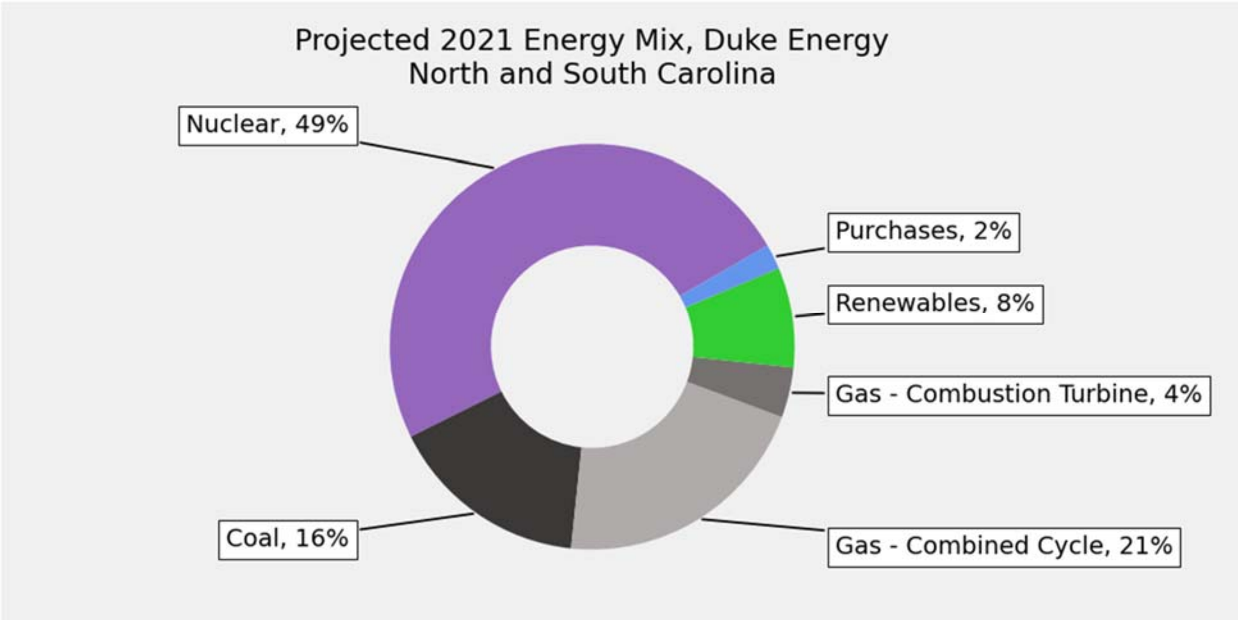

Figure C-2. *Energy mix of Duke Energy Carolinas and Duke Energy Progress combined, projected for 2021.*[82] *Note that wind and solar, hydro, and energy efficiency are all included in 'renewables.'*

Duke Energy's projected energy mix for the Carolinas in 2021 is provided in Figure C-2. DEC and DEP rely on nuclear plants for just under half of all energy generation. Fossil-fueled resources, including coal-powered steam plants, gas-powered combined cycle plants, gas-powered combustion turbines, contribute another 40 percent. The remaining 10 percent is satisfied by renewables (mostly utility-scale photovoltaic solar), energy efficiency and demand-side management, and hydroelectricity, with two percent of energy imported from other utility systems. In recent years, DEC and DEP have pursued gradual retirement of their legacy coal fleet in favor of cheaper gas-powered generators. While Duke Energy's footprint in the Carolinas gets a zero-emissions boost from large nuclear fleet, the Duke utilities' fossil-fueled portfolio still represents one of the largest sources of carbon emissions in the Southeast.[83]

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[82] DEC IRP Report, p. 107.

[83] Southern Alliance for Clean Energy (2019). Tracking Decarbonization in the Southeast 2019. Retrieved at: https://cleanenergy.org/wp-content/uploads/Decarbonization-in-the-Southeast-2020.pdf.

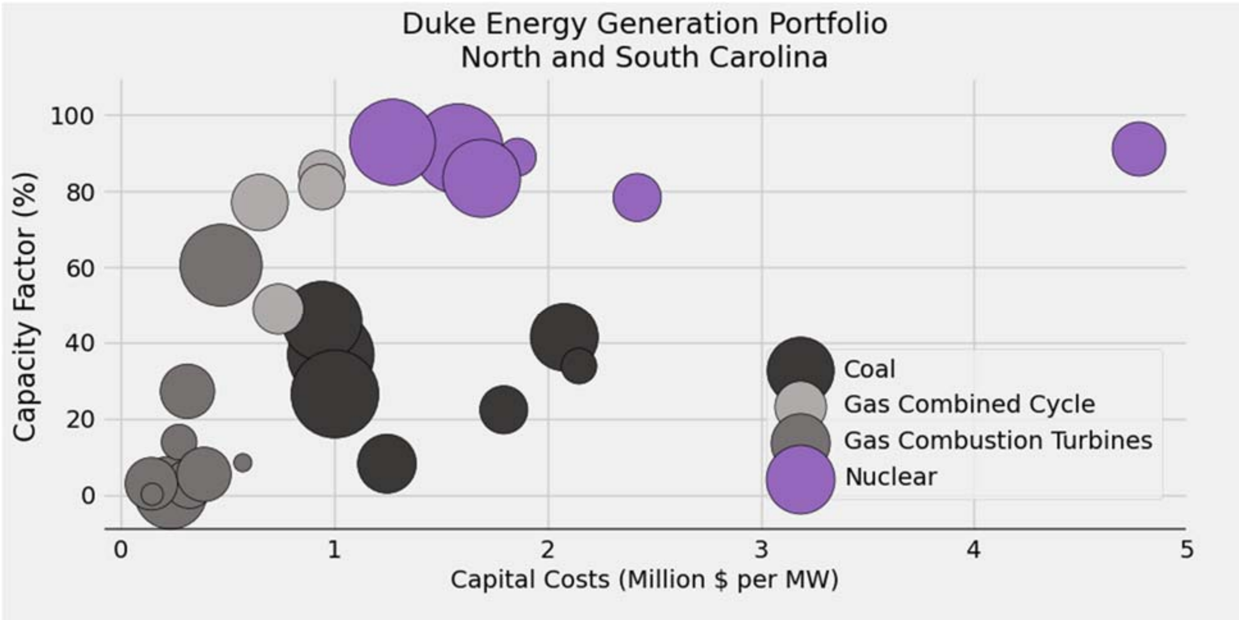

Figure C-3. *Capacity Factor and Capital Costs of Duke Generating Units in the Carolinas.*[84]

Figure C-3 shows a simplified schematic of the large power generation plants owned and operated by Duke Energy in the Carolinas, as the companies reported to the Federal Energy Regulatory Commission in 2018. The x-axis shows the capital costs to build the plant, on a per-megawatt basis; plants further right on the x-axis are relatively more expensive, normalizing for size (the highest-cost outlier is the Shearon Harris Nuclear Power plant). The y-axis shows capacity factor, or how much the plant was in operation over the course of the year (in the case of this graph, 2018). Plants near the top of the y-axis were generating electricity at full capacity for almost every hour of the year; plants near the bottom of the y-axis only generated electricity for a few hours a year. Finally, the size of the dots on the graph represents the capacity of the unit, or the maximum amount of power it is able to generate at a time. The smallest unit in the fleet by capacity is Duke Energy Progress' oil-burning Blewett plant at 70 megawatts; the largest is Duke Energy Carolinas' Oconee nuclear plant at 2,666 megawatts.

Taken as a whole, the graph shows the types of large plants used to serve load in the Carolinas. The large, purple dots in the upper right of the graph's area represent the utility's nuclear fleet, which is relatively expensive and runs on an almost constant basis. Near the origin of the graph are the dark

[84] Data from FERC Form 1.

gray gas combustion turbines, which tend to be smaller and cheaper than the other options but operate for relatively few hours. Gas combined cycle plants represent a midpoint in cost and capacity factor between the nuclear fleet and the combustion turbines, and coal plants are generally larger and more expensive, but run less than half of the time.

ii. Duke Energy's 2020 Integrated Resource Plans

As directed by regulatory authorities in North and South Carolina, Duke Energy Carolinas and Duke Energy Progress release an updated Integrated Resource Plan every two years, with an update published in the year between IRPs. Integrated Resource Plans include a 15-year planning horizon for new generation. In North Carolina, the North Carolina Utilities Commission does not explicitly approve or reject the IRP or any specific investment described within; instead, it determines whether the IRP is suitable for planning purposes. Then, when utilities seek permission to build new large generation units, they are approved or rejected roughly according to their inclusion in the most recent integrated resources plan.

Context: Increasing momentum on carbon reduction

Despite the short 2-year period between IRPs, the 2020 IRP for Duke Energy Progress and Duke Energy Carolinas sets an important precedent for the Carolinas' carbon emissions pathway. The following circumstances provide context for the 2020 IRPs.

Duke's Net-Zero Carbon Commitment.[85] In September 2019, Duke Energy committed to reaching net zero emissions across its corporate portfolio by 2050.[86] The announcement is a bold proclamation from one of the largest electric utilities in the country and a resounding signal that the transition to a zero-carbon energy system is underway. The 2020 Integrated Resource Plan represents Duke Energy's first long-term planning document in the Carolinas since the announcement of the net-zero carbon

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[85] Duke Energy materials sometimes refer to their net-zero by 2050 aim as a 'goal,' and other times as a 'commitment.'

[86] Duke Energy (2019, September). Duke Energy Aims to Achieve Net Zero Carbon Emissions by 2050. Retrieved at: https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050.

commitment. As discussed in the previous section, climate commitments are a double-edged sword of reputational risk; they may preserve social license in the short term, but only if the company can show it intends to meet its goal. As stated in the 2020 IRPs, these plans represent a "road map" for Duke Energy to demonstrate follow-through on its commitment.[87]

Cancellation of the Atlantic Coast Pipeline. Duke Energy and Dominion Energy announced the cancellation of the Atlantic Coast Pipeline in July 2020.[88] The companies had already spent $3.4 billion on the project, and the pipeline's course was slated to extend for 600 miles, crossing the Appalachian Trail. In a release to press after the announcement of the cancellation, Duke Energy noted that while the pipeline was a "critical piece of Duke's decarbonization strategy," Duke would "continue advancing its ambitious clean energy goals by investing in renewables, battery storage, energy efficiency programs and grid projects" in the absence of the Atlantic Coast Pipeline.[89] The Atlantic Coast Pipeline could signal a shift for how utilities in the Southeast pursue decarbonization and securing energy resources, and Duke Energy's Integrated Resource Plans in the Carolinas provide a window into that shift.

State Action. Since the development of Duke Energy's previous integrated resource plans for the Carolinas, momentum has built around state action on climate risks and opportunities. North Carolina Governor Roy Cooper's Executive Order 80 created a framework for the state to assess its own vulnerabilities to climate change and envision a decarbonized energy system.[90] Since EO 80 was signed in 2018, state agencies and a broad group of stakeholders have worked to make the Order's programs concrete and implementation-ready. In October 2019, the North Carolina Department of Environmental Quality released a Clean Energy Plan in consultation with stakeholders across the state that targets a 70 percent reduction in greenhouse gas emissions from the power sector by 2030 and

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[87] DEC IRP, p. 8.

[88] Duke Energy (2020, July). Dominion Energy and Duke Energy cancel the Atlantic Coast Pipeline. Retrieved at: https://news.duke-energy.com/releases/dominion-energy-and-duke-energy-cancel-the-atlantic-coast-pipeline.

[89] Duke Energy (2020, July). The Road Ahead: An Update on the Atlantic Coast Pipeline. Retrieved at: https://www.myncma.org/download/public_documents/atlantic-coast-pipeline-FAQ-one-pager-FINAL-sm.pdf.

[90] State of North Carolina.

carbon neutrality by 2050.[91] In South Carolina, these plans represent Duke's first filed under the new Integrated Resource Plan requirements included in the Energy Freedom Act passed in 2019.[92] In May 2020, a consortium of universities in North Carolina released the North Carolina Climate Science Report, which projects large changes in the State's physical environment through the end of the century.[93] These reports are changing the understanding of climate risk and the public interest in the Carolinas, and Duke Energy has an opportunity to be responsive to these shifts in its integrated resource plan.

Increased Commission attention. As discussed in Section B of this report, state utilities commissions are not insulated from concerns over long-term climate risks and opportunities. In North Carolina, the North Carolina Utilities Commission has specified elements associated with climate risk that Duke Energy must address in its 2020 Integrated Resources Plan:

- Duke Energy should continue to model the impacts of potential carbon regulation on its plan;
- The Companies should remove any assumption that coal plants continue to operate uneconomically, and present portfolios that retire Duke Energy's coal fleet by the "earliest practicable date;"
- Duke Energy should further develop its previous illustrative scenarios for decarbonization by subjecting them to a more rigorous IRP process;
- Duke Energy should discuss the use of "all-source" procurement of energy resources, rather than choosing from conventional alternatives.[94]

Notably, the North Carolina Utilities Commission has been tracking some of these issues since Duke Energy's 2018 Integrated Resource Plans. In those proposals, the utilities sought approval for a buildout

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[91] NC DEQ.

[92] Robbins, S., & Mango, M., (2019, July). "Commentary: With Energy Freedom Act, South Carolina takes steps toward resilience." *Energy News Network.* Retrieved at: https://energynews.us/2019/07/25/southeast/commentary-with-energy-freedom-act-south-carolina-takes-steps-toward-resilience.

[93] Kunkel *et al.*

[94] DEC IRP Report, Table N-3.

of over 10 gigawatts of new gas-fired generation;[95] the NCUC ultimately did not accept the 2018 IRP for planning purposes beyond 2020 because it "[did] not accept some of the underlying assumptions upon which DEC's and DEP's IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled."[96]

In South Carolina, Duke Energy's Plans are the first filed by Duke since the passage of the Energy Freedom Act, which substantially overhauled the IRP process in the state.[97] The Energy Freedom act directs utilities to present high-renewable scenarios as a part of its plan, and empowers the Commission to conduct a robust hearing to determine the prudency of utilities' long-term plans, considering factors including "commodity price risks" and other foreseeable conditions the Commission determines to be for the public interest. In December 2020, the South Carolina Public Service Commission found that Dominion Energy did not "properly assess risk and uncertainty" in its filed IRP, the first in the state under the new Act.[98]

In both states, Duke Energy's plans are subject to new attention on climate risks, and the tailwinds for climate-informed resource planning demonstrate the immediacy and magnitude of climate-related risks and opportunities.

Duke Energy's Filing

Duke Energy Carolinas and Duke Energy Progress filed their Integrated Resource Plans with the NC and SC Commissions on September 1, 2020. Rather than proposing a single integrated resource plan as the recommended pathway, the filings instead include six scenarios according to requests from state

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[95] Walton, R., (2018, September). "Duke 15-year plans lean heavy on gas to replace coal." *UtilityDive.* Retrieved at: https://www.utilitydive.com/news/duke-15-year-plans-lean-heavy-on-gas-to-replace-coal/531924/.

[96] North Carolina Utilities Commission (2019, August). Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses. Docket No. E-100, Sub 157. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=143d85de-b1e7-4622-b612-5a8c77e909d4.

[97] South Carolina Office of Regulatory Staff (2019, September). Summary of the South Carolina Energy Freedom Act. Retrieved at: http://www.energy.sc.gov/files/view/SC%20Energy%20Freedom%20Act_summary%2009.012.2019.pdf.

[98] South Carolina Public Service Commission (2020, December). Order No. 2020-832. P. 18.

utilities commissions and a broader community of stakeholders. Despite the presence of these alternative scenarios, Duke Energy clarifies that it considers only its 'base cases' as "suitable for planning purposes."[99] A table summarizing the six scenarios is provided below.

Table C-1. *Duke Energy's Combined Integrated Resource Plan Scenarios*

Scenario Name	**Base w/o Carbon Policy**	**Base w/ Carbon Policy**	**Earliest Practicable Coal Retirements**	**70% CO_2 Reduction: Wind**	**70% CO_2 Reduction: SMR**	**No New Gas**
Relevant Commission Direction	n/a	Directed by NCUC[100]	Directed by NCUC[101]	Directed by NCUC[102]	Directed by NCUC[103]	Requested by stakeholders
Planned new gas generation by 2035 (MW)	9,600	7,350	9,600	6,400	6,100	0
Total Solar online by 2035 (MW)	8,650	12,300	12,400	16,250	16,250	16,250
Total New Wind by 2035 (MW)	0	750	1,350	5,500	3,100	5,800
Total New Nuclear by 2035 (MW)	0	0	0	0	1,350	700
Total New Storage by 2035 (MW)	1,050	2,200	2,200	4,400	4,400	7,400
Carbon Reduction Achieved by 2030 | 2035	56% | 53%	59% | 62%	64% | 64%	70% | 73%	71% | 74%	65% | 73%
Present Value Revenue Requirement through 2050 ($, billions)	$79.8	$82.5	$84.1	$100.5	$95.5	$108.1
Dependent on supportive policy?	Not dependent	Slightly dependent	Moderately dependent	Mostly dependent	Entirely dependent	Entirely dependent

[99] DEC IRP Report, p. 97.

[100] NCUC, (2020, April), P. 7.

[101] NCUC, (2020, April). P. 8.

[102] NCUC, (2020, April)., p. 9.

[103] *Ibid.*

Duke's six scenarios provide a window into Duke's strategy for planning its portfolio under emerging climate risks. The scenarios are briefly summarized below.

- The **Base Case without Carbon Policy** provides a resource plan according to Duke's conventional, historical planning process.
- The **Base Case with Carbon Policy** adds a modest additional cost to carbon emissions, starting at $5 per ton in 2025 and escalating by $5 per year.
- **Earliest Practicable Coal Retirements** does not include a carbon policy, but retires coal plants at the earliest possible date, given necessarily transmission and distribution upgrades.
- The **70 percent CO_2 Reduction Scenarios** demonstrate two potential portfolios that would meet the North Carolina Clean Energy Plan scenarios of 70 percent carbon reduction (from 2005 levels) by 2035. One assumes the availability of offshore wind resources for the Carolinas; the other assumes the viability of small, modular nuclear reactors (SMRs).
- Finally, the **No New Gas** scenario provides Duke Energy's perspective on what a no-new-gas planning portfolio would look like.

With the exception of the No New Gas portfolio, each of Duke's presented scenarios involve a substantial buildout of gas-fired generation, from 6.1 gigawatts to 9.6 gigawatts (for context, the total gas portfolio between DEC and DEP has a current capacity of approximately 12.4 gigawatts). The portfolios also expect continued investment in solar resources in the Carolinas, up to 16.2 gigawatts in the high-solar scenarios. Depending on the scenario, wind, storage, and nuclear resources are also tapped to meet energy needs in the Carolinas.

On the other hand, the base cases do not represent a substantial departure from previous integrated resource plans in terms of their treatment of solar and gas assets. Table C-2, from Duke Energy's ESG Analyst day in October 2020, show selected attributes of the 2019 and 2020 base cases. Although coal retirements have changed significantly according to NCUC direction and new gas investment has decreased, the broad outlines of the plan are quite similar.

Table C-2. *Comparing selected attributes of Duke Energy's 2019 and 2020 IRPs in the Carolinas*[104]

	2019 IRP Base with Carbon Policy	**2020 IRP Base without Carbon Policy**
System CO_2 Reduction (2030 | 2035)	50% | 48%	59% | 62%
Total Solar [MW]	8,400	8,650
Incremental Wind, Onshore and Offshore Combined [MW]	0	0
Incremental SMR Capacity [MW]	0	0
Incremental Storage [MW]	550	1,050
Incremental Gas [MW]	11,550	9,600
Coal Retirements by 2035 [MW]	6,000	7,000

The final two rows in table C-1 represent Duke Energy's assessment of the financial and policy requirements of these scenarios. Duke Energy identifies the base case without carbon policy as the most affordable and the least policy-dependent option, while the No New Gas scenario is conversely the least affordable and most policy-dependent.

It is important to contextualize these assessments. First, portraying costs as present-value through 2050 may not provide a straightforward picture of cost impacts. The costs of assets built or purchased later in the planning horizon will be discounted more steeply, and costs incurred after 2050 are not included

[104] Duke Energy (2020, October). Delivering Sustainable Value: Our ESG Progress and Promise. Retrieved at: https://www.duke-energy.com/_/media/pdfs/our-company/investors/news-and-events/esg-investor-day-presentation.pdf?la=en.

in Duke's assessment. By contrast, assets built or purchased early in the planning horizon will be discounted little and may be recovered completely by 2050.

Second, these assessments provide an incomplete picture of Duke Energy's exposure to risks and opportunities, including climate-related risks. If any of the proposed conventional plants were to be out-competed by renewable resources mid-way through their expected lifetime, for example, the stranded asset costs could be borne by ratepayers even as Duke Energy continues to invest in new generation resources.

iii. Treatment of Climate Risk within the Integrated Resource Plans

The 2020 IRPs represent a critical junction in Duke Energy's response to climate risks and opportunities. The IRP planning horizon of 15 years encompasses exactly half of the time between now and 2050, the common goal for a carbon neutral power sector. Investments made in the next 15 years will almost certainly be in operation in 2050, and proposed gas plants under some proposed scenarios will have engineering lifetimes into the 2070s. Given the emerging materiality of climate risk to Duke Energy shareholders, customers, regulators, and legislators in the Carolinas, a climate-risk informed resources plan would be in the public interest.

Unfortunately, the integrated resource plans are light on details in terms of meeting their commitments and mitigating long-term climate-related risk. The Commission-directed scenarios present a relatively robust picture of what meeting short-term 2030 goals are, but very few details are provided on pathways between 2030 and Duke's ultimate net-zero by 2050 commitment. Modest emissions reductions in the short-term emerge from Duke Energy's decision to expand gas generation to replace its coal fleet, but such a decision necessarily 'locks in' new emissions for decades as gas-fired power plants operate for their engineered lifetime.[105]

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[105] Erickson, P., Kartha, S., Lazarus, M., Tempest, M., (2015, August). Assessing Carbon Lock-in *Environmental Research Letters.* Retrieved at: https://dx.doi.org/10.1088/1748-9326/10/8/084023.

Looking to other jurisdictions with zero-by-2050 commitments may be instructive. Utilities in California, for instance, are proposing no new gas plants, opting instead to operate the ones that are already existing.[106] In Virginia, Dominion revised their integrated resource plan after the passage of the zero-by-2050 Virginia Clean Economy Act, noting that "significant build-out of natural gas generation facilities is not currently viable, with the passage by the General Assembly of the Virginia Clean Economy Act of 2020."[107] The plans contemplated in Duke Energy's IRPs in the Carolinas are out of step with these examples. If implemented as written, the plans would create a material tension between operating a newly-built fleet of gas-fired generation through their engineering lifetime and meeting a net-zero carbon commitment.

Duke Energy's IRPs do include a high-level discussion of long-term compliance with its carbon goals and reconciling a gas buildout with a pathway toward net-zero emissions. The options discussed by the company merit consideration. In particular, the IRP mentions technological solutions such as green hydrogen or renewable, zero-emission gas. While analysts have found these technologies may have a feasible role in a zero-carbon electricity system, scaling these technologies to completely replace fossil fuel needs for existing plants would entail transformative, national investment.[108] The IRPs do not appear to consider or quantify the additional costs of these investments, and therefore do not meaningfully engage with the economic implications of these technological fixes within the Plans.

In lieu of technological fixes, Duke Energy has offered a financial solution through accelerated depreciation, recovering the value of gas-powered plants much more quickly than the plant's

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[106] Roth, S., (2020, September). "Boiling Point: California won't need to kill fossil fuel plants. They're dying of old age." *LA Times.* Retrieved at: https://www.latimes.com/environment/newsletter/2020-09-24/fossil-fuel-plants-ladwp-methane-stranded-assets-boiling-point.

[107] Virginia Electric and Power Company (2020, March). Motion for Relief from Certain Requirements Contained in Prior Commission Orders and for Limited Waiver of Rule 150. Commonwealth of Virginia State Corporation Commission Case No. PUR-2020-00035. Retrieved at: https://scc.virginia.gov/docketsearch/DOCS/4m0c01!.PDF.

[108] Phadke, A., Aggarwal, S., O'Boyle, M., Gimon, E., Abhyankar, N., (2020, September). Illustrative Pathways to 100 Percent Zero Carbon Power by 2035 Without Increasing Customer Costs. Energy Innovation. Retrieved at: https://energyinnovation.org/wp-content/uploads/2020/09/Pathways-to-100-Zero-Carbon-Power-by-2035-Without-Increasing-Customer-Costs.pdf.

anticipated lifetime. The Integrated Resource Plans contemplate shortening the "lifetime" of gas plants to twenty-five years,[109] and Duke executives have publicly discussed accounting lifetimes as short as fifteen years.[110] Accelerated depreciation used in this way would allow Duke Energy to build new gas-fired generation with the expectation that these assets would become stranded midway through their lifetimes, while charging ratepayers a premium and insulating the utility from any stranded value. The extra costs to ratepayers of stranded gas assets, accelerated depreciation, or the costs of new generation to replace stranded gas assets are not reflected in the Integrated Resource Plans as presented.

Despite discussion of potential technological and financial alternatives, the Duke Energy Integrated Resource Plans do not adequately explore the exposure of the utility and its ratepayers to long-run climate-related risks. Especially as the Duke utilities contemplate a substantial buildout of new carbon-emitting generation, lack of clarity and transparency on these long-run risks should present concerns to policymakers, ratepayers, regulators, and utility management alike.

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[109] DEC IRP Report, p. 136.

[110] Morehouse, C,. (2019, October). "Duke VP likens gas plant buildout strategy to 15-year home mortgage on path to zero carbon." *UtilityDive.* Retrieved at: https://www.utilitydive.com/news/duke-vp-likens-gas-plant-buildout-strategy-to-15-year-home-mortgage-on-path/565328/.

D. Assessing Carbon Stranding Risks in Duke Energy's 2020 Integrated Resource Plans

Previous sections of this report discussed the duty of utilities and regulators to ensure that capital investments by the utilities serve the public interest and meet a 'used and useful' standard throughout their lives. Assets that are no longer used and useful after construction present particularly salient risks to ratepayers because utilities have not always borne the full cost burden of these stranded assets. And, as new technologies and challenges transform the energy grid, the potential for stranded assets and increased costs allocated to ratepayers is higher than ever. Duke Energy's Integrated Resource Plans in the Carolinas introduce an acute 'carbon stranding' risk because of the anticipated build out of gas-fired generation in the face of climate-related risks and opportunities. This section will provide a quantitative assessment of the 'carbon stranding' risk to ratepayers in the 2020 Duke Energy Carolina and Duke Energy Progress IRPs.

This analysis takes inspiration from previous research by Oxford University's Sustainable Finance Programme[111] and Dr. Emily Grubert at Georgia Tech,[112] who modeled future carbon emissions from utilities' existing and proposed fossil generation fleets based on historical plant operation and estimated the impacts of carbon constraints. By comparing modeled future carbon emissions to low-carbon pathways and goals like the North Carolina Clean Energy Plan and Duke Energy's net-zero commitment, the analysis quantifies the discrepancy between stated commitments and modeled future operations, then attempts to quantify the costs of "righting the course" to meet carbon commitments after new fossil generation is operational.

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[111] Saygin, D., Rigter, J., Caldecott, B., Wagner, N., & Gielen, D., (2019, May). Power sector asset stranding effects of climate policies. Energy Sources, Part B: Economics, Planning and Policy 14:4, pp. 99-124. Retrieved: https://www.tandfonline.com/doi/abs/10.1080/15567249.2019.1618421.

[112] Grubert, Emily, (2020, December). Fossil electricity retirement deadlines for a just transition. *Science* 370:6521, pp. 1171-1173. Retrieved at: https://science.sciencemag.org/content/370/6521/1171.

Importantly, climate-related transition risks are not discrete: There is no single emissions 'cap' where climate risks begin to impede assets or operations, but risks accelerate as emissions exceed stated goals. This analysis uses Duke Energy's corporate commitments to 50 percent carbon reduction by 2030 and net-zero by 2050 as broad indicators for climate risk generally. To the extent that the Duke Energy utilities' portfolios are in compliance with their commitments, their portfolio is not considered at risk for carbon stranding. To the extent that the portfolio's projected emissions exceed the commitments, assets are at risk for carbon stranding. Breaching corporate commitments are just one of several causes for stranded carbon-emitting assets, as demonstrated by BloombergNEF[113] and Rocky Mountain Institute[114] analyses; in this case, the corporate commitment is used as a proxy for climate-related risk generally.

This analysis does not quantify all costs encompassed in an Integrated Resource Plan, and the 'carbon stranding' costs discussed throughout are just one component of the costs that ratepayers in the Carolinas will pay in the future. Nevertheless, these costs are of particular salience to ratepayers because of the likelihood that ratepayers will bear the burden, despite these units not meeting a future 'used and useful' standard. For more detailed information on the methods used in this analysis, see the Appendix.

i. Projecting Future Emissions

Based on Duke Energy's statements identifying the base cases as suitable for planning,[115] analysis provided throughout will use the Base Case with Carbon Policy scenario, combined for both Duke Energy Carolinas and Duke Energy Progress.

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[113] BloombergNEF.

[114] Gimon *et al.*

[115] DEC IRP Report, p. 97.

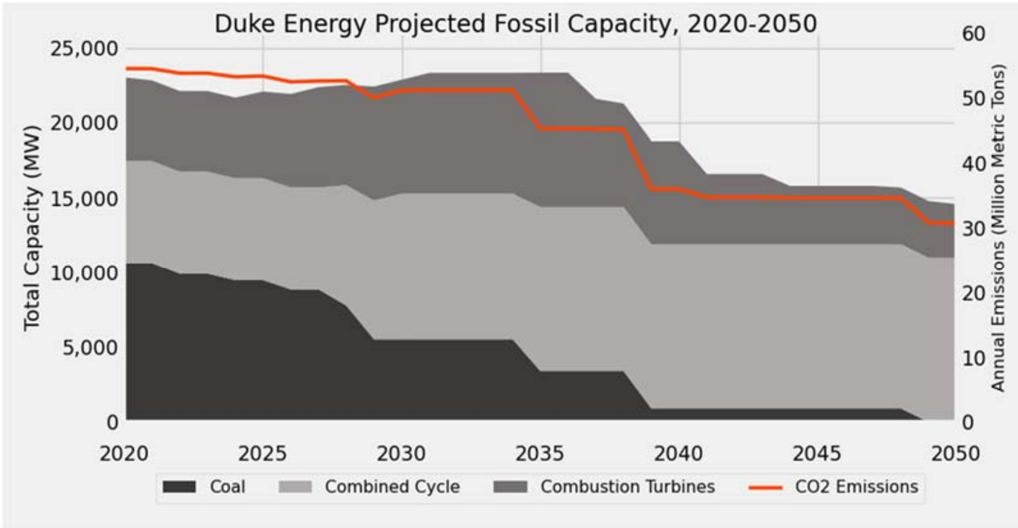

Figure D-1. *Duke Energy Projected Fossil Capacity and Emissions, 2020-2050.*

Figure D-1 shows current and proposed capacity of conventional coal generation, gas combined-cycle units, and gas combustion turbines from year 2020 to 2050. The x-axis represents time from 2020 to 2050. The shaded areas show total capacity of fossil-fueled generating plants in Duke's portfolio (the left y-axis shows operating capacity in megawatts). While the portfolio sees a decrease in coal capacity through 2035 as legacy assets retire, the decrease is offset by increases in gas generation capacity. Then, after 2035, emissions and fossil capacity fall as legacy gas and combined-cycle plants retire. It is important to note that the planning horizon for the Integrated Resource Plans is 15 years, so the Base Case scenario does not include any further investments after 2035 (although it is likely that more capacity will be proposed and built in this time to meet resource adequacy constraints). Nevertheless, Duke Energy projects that over 14,000 megawatts of gas generation capacity will still be operational in 2050.

The red line shows projected carbon emissions for each year, based on the projected fossil fleet (the right y-axis shows total CO_2 emissions, in million metric tons). Carbon emissions for 2020 are projected based on the fleet's operation in the years 2016-2018; this analysis assumes that both existing and proposed plants will be operated with similar capacity factors and emissions per megawatt-hour generated as seen in 2016-2018 across the entire generation fleet. Using these assumptions, the red line projects carbon emissions 2020-2050. Notably, these emissions totals do not reflect upstream emissions from gas production and transport.

Importantly, emissions are not projected to fall to near zero by 2050 based on the proposed portfolio and Duke's typical operation of this portfolio. In fact, they decline just 44 percent between 2020 and 2050. These projections represent a substantial departure from the Company's commitment to net-zero by mid-century, assuming that Duke Energy is not planning to use offsets for tens of millions of tons of emissions per year. Figure D-2 shows the difference between a linear path to the Company's goal and projected emissions based on its portfolio. By 2050, the difference between projected emissions for the Carolinas and Duke Energy's corporate commitment is approximately 30 million metric tons.

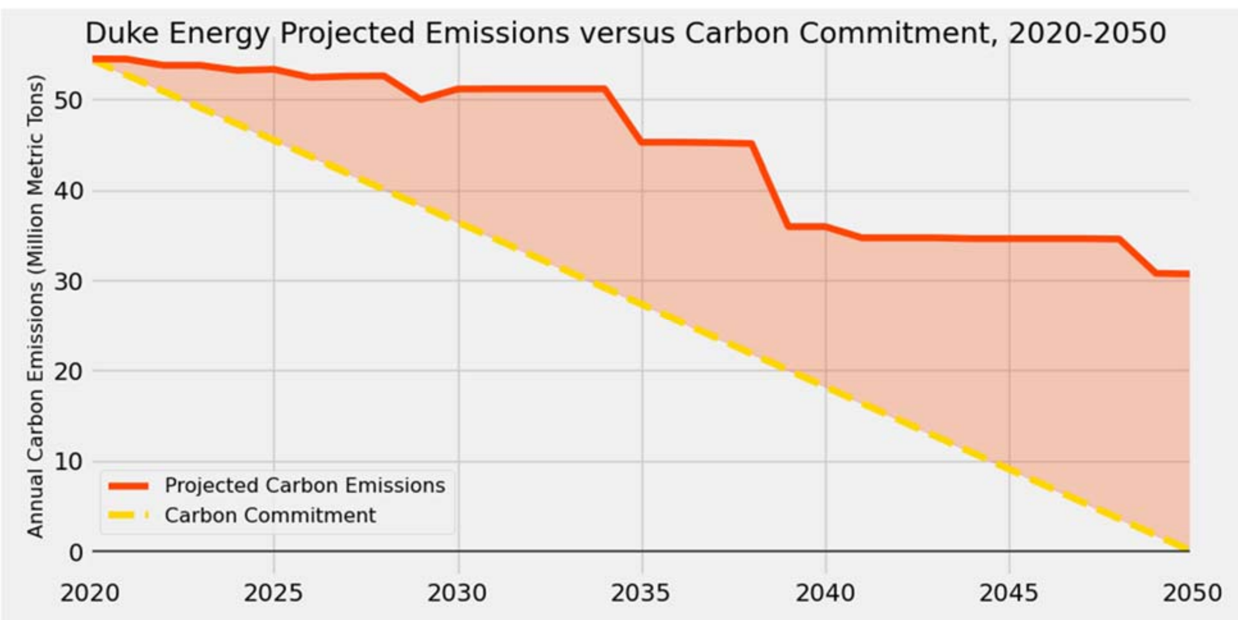

Figure D-2. *Duke Energy Projected Emissions versus its net-zero commitment, 2020-2050.*

The large difference between these carbon projections and Duke Energy's commitment highlight a discrepancy between Duke Energy's current operating protocol and its ambitions for 2050. If Duke pursues its base-case integrated resource plan and plans to meet its commitments, two options present themselves: either the plants must be downrated or shut down altogether before their operational lifetimes are over, or Duke Energy will need to invest substantial capital in hypothetical technologies to decarbonize their existing generation. Either way, a dramatic shift will be needed, and it will create additional, unnecessary costs for ratepayers.

ii. The Cost of Carbon Stranding

As shown above, Duke Energy's portfolio in the Carolinas is likely to exceed its corporate net-zero by 2050 commitment if plants are allowed to operate as normal. Therefore, Duke Energy will need to either use plants less than expected or remove them from the operating fleet earlier than expected to maintain compliance with their carbon commitment.

Analysis presented here attempts to characterize that phenomenon. First, the model determines how much carbon-emitting capacity would be taken offline every year to continue to meet carbon constraints. Then, the model calculates the depreciation and return on investment costs to ratepayers for stranded capacity (ratepayers are presumed to continue to pay for assets that have been taken offline until their expected retirement date). Emissions are modeled for each year, starting with 2020 and through 2050. If the modeled emissions are higher than the carbon commitment pathway shown in Figure D-2, then units are taken offline—effectively 'stranded'—until the modeled emissions are in compliance with carbon commitments. The model completes this process for every year, 2020-2050, continuing to remove additional capacity as needed to meet carbon constraints. For the purposes of this exercise, fossil generation units are retired and 'stranded' in order by technology (coal, then combined cycle, then combustion turbine), then by carbon intensity (most carbon-intense generation first), then by age (oldest first). Combustion turbines are preserved because they are most likely to be used as 'peaking' resources in concert with renewables.

To better understand the financial impacts of carbon stranding, a look at an individual plant may be helpful. 'Carbon stranding' of a combined-cycle gas plant planned to enter operation in 2035 is presented in Figure D-3.

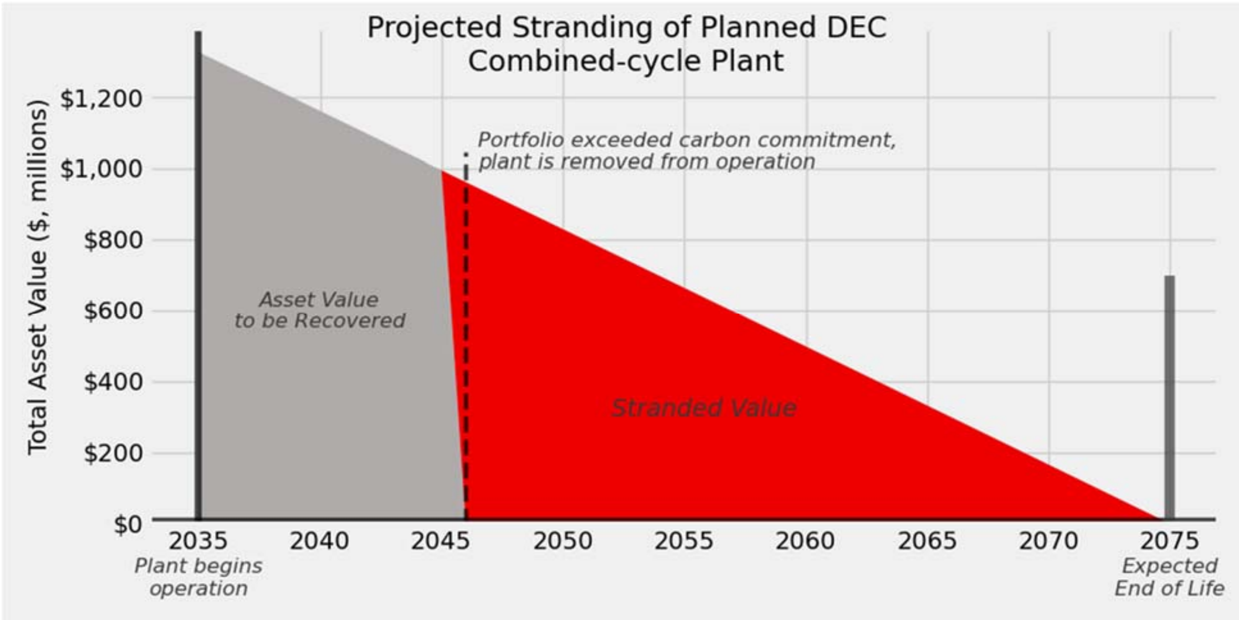

Figure D-3. *Asset value and stranding of Duke Energy Carolinas combined-cycle gas plant, planned to be completed in 2035.*

This plant is planned to complete construction in December 2034 and enter operation in 2035. The total amount that ratepayers are expected to pay for the plant, including return on investment, is $1.4 billion. Each year, the asset's value depreciates over its 40-year lifetime until a planned retirement year of 2075. During the carbon-constrained run, however, the portfolio exceeds its carbon commitment in 2045. Because all coal plants and older combined-cycle plants had already been retired, this plant is removed from generation, stranding its remaining value. In this example, ratepayers would continue to pay the depreciation and return-in-investment on this asset even though it was removed from generation for another 30 years, totaling over $1 billion.

A portfolio-level look at the carbon-constrained portfolio following Duke Energy's Base Case with Carbon Policy is presented in Figure D-4.

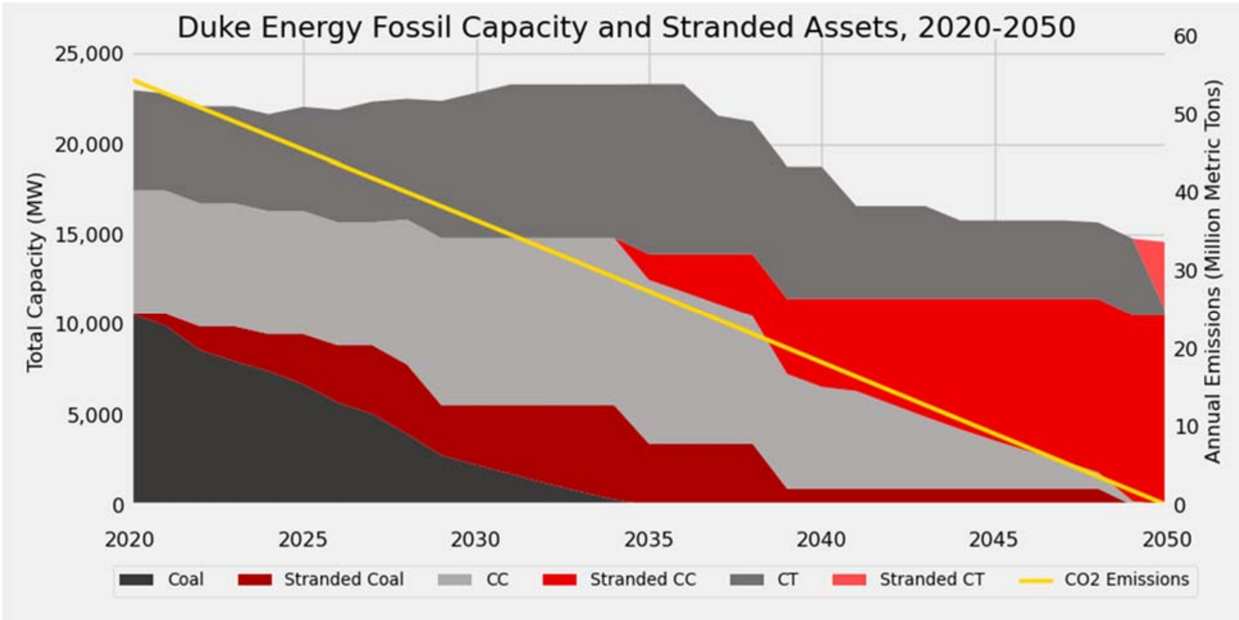

Figure D-4. *Duke Energy Portfolio, with carbon stranded assets to meet climate commitments.*

In Figure D-4, areas shaded in red represent units and capacity that have been taken offline and 'stranded' in order to meet climate commitments. Additional carbon stranding occurs in every year, 2020-2050, with coal exiting the portfolio entirely in 2034 and a substantial amount of combined cycle assets are retired by 2040. Notably, no combustion turbines are retired until 2049-2050. This is because combustion turbines' capacity factors are very low—often below 5 percent—and therefore they contribute very little to total emissions.

Duke Energy reports capital costs for each generation plant in its reporting to the Federal Energy Regulatory Commission every year, and this analysis uses Duke's 2018 FERC filings to calculate annual depreciation and return-on-investment for each plant. Depreciation and return costs paid by ratepayers for carbon stranded assets represents carbon stranding costs. Total stranding costs for the portfolio, 2020-2050, are provided in Figure D-5.

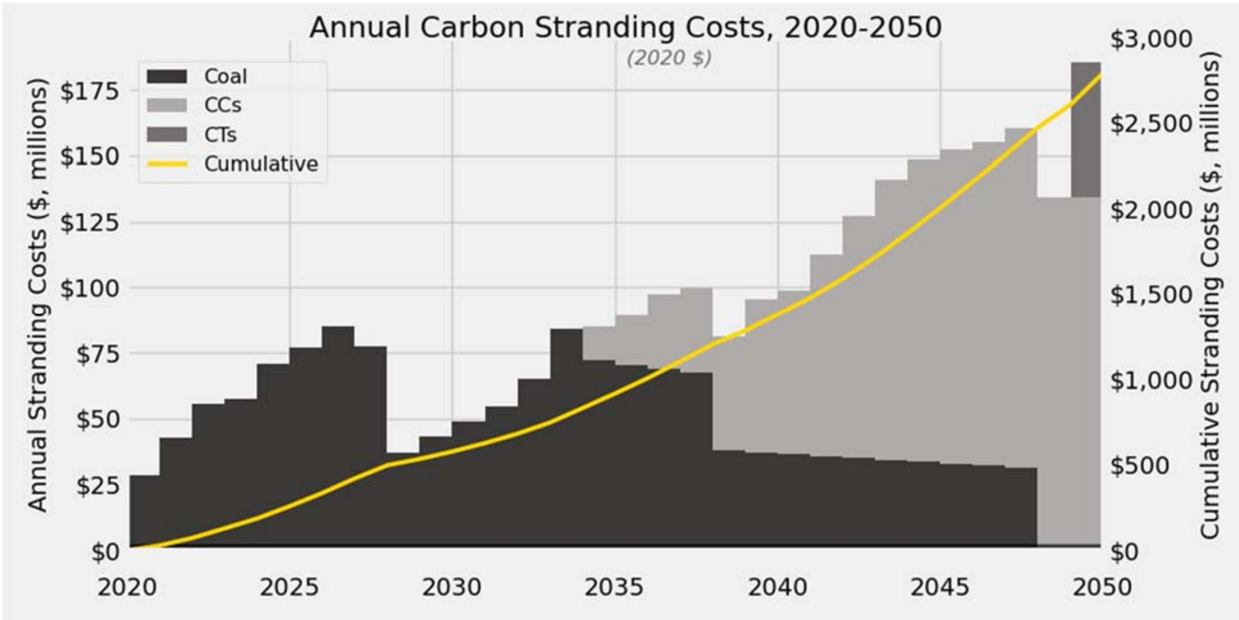

Figure D-5: *Annual and Cumulative Carbon Stranding Costs, 2020-2050. All amounts are in millions USD, adjusted for inflation.*

Through 2035, annual carbon stranding costs to ratepayers are on the order of $50 million per year. By 2050, though, carbon stranding costs increase to as much as $175 million per year. Cumulatively from 2020 to 2050, this analysis projects that carbon stranding costs would accumulate to $2.8 billion in 2020 dollars by 2050. Notably, because combustion turbines are less capital-intensive than combined-cycle or coal plants, they have a relatively small contribution to stranding costs through 2050.

Despite 2050 being the target year of Duke's carbon commitment, gas generation would still be online and would therefore still create costs for ratepayers after 2050. Figure D-6 extends the previous figure to the end of the engineering lifetime of the last proposed plant in 2075.

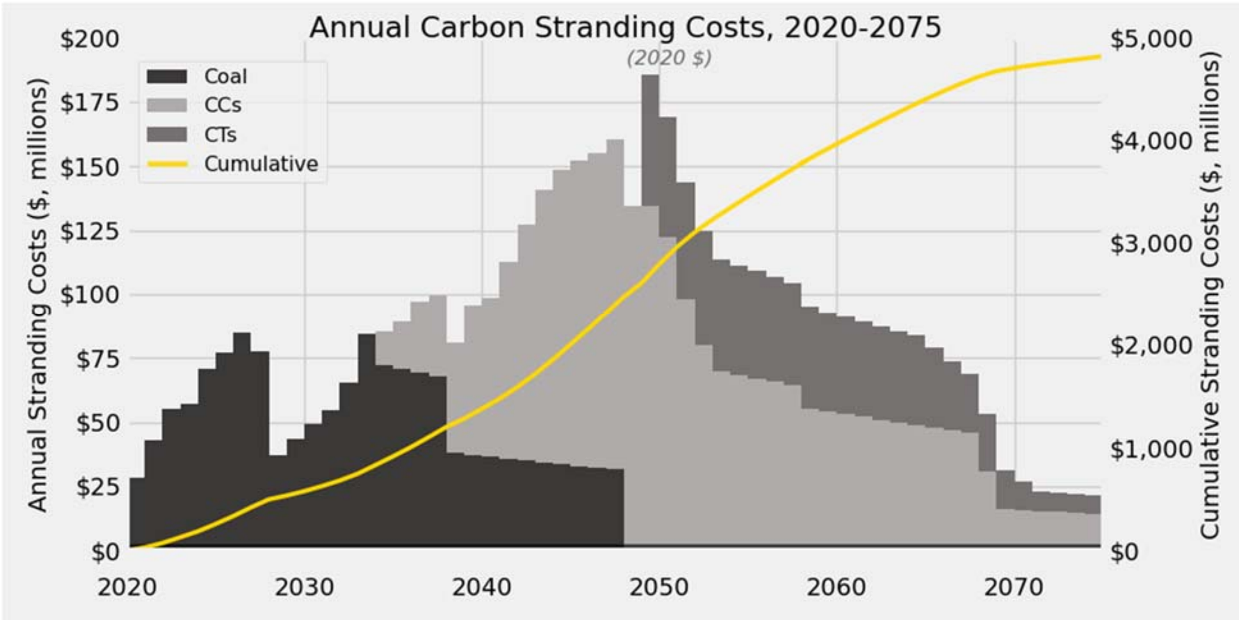

Figure D-6. *Annual and Cumulative Carbon Stranding Costs, 2020-2075. All amounts in millions USD, adjusted for inflation.*

Ratepayers would continue to pay off non-operational gas assets through 2075. Over the lifetime of all of these assets, carbon stranding costs would accumulate to about **$4.8 billion** in 2020 dollars, exceeding the total stranded investment cost to Duke Energy and Dominion Energy combined on the Atlantic Coast Pipeline by over $1 billion. If this sum were to be invested in utility-scale solar at 2019 prices, $4.8 billion could drive almost 3.4 gigawatts of additional solar in the Carolinas. Using a social discount rate appropriate for discounting climate-related costs, the present value of carbon stranding in Duke Energy's Integrated Resource Plans in the Carolinas is **$3.3 billion**.[116] To put this number in context, $3.3 billion represents a **present value cost of $900 to every residential Duke customer in the Carolinas.** Key values from this analysis are presented in Table D-1.

[116] In its recommendations to the New York State Energy Research and Development Agency (NYSERDA), the research institution Resources for the Future provided climate-related costs at 0, 1, 2, and 3 percent discount rates. This analysis uses a mean discount rate of 1.5 percent. See https://www.dec.ny.gov/docs/administration_pdf/vocfguid.pdf for additional details.

Table D-1. *Key Results of Duke Energy Carbon Stranding Analysis*

Projected GHG Emissions Overshoot in 2050	30 million metric tons
Engineering lifetime of new-build combined-cycle gas plants	40 years
Projected operational lifetime of new-build combined-cycle gas plants	12.3 years
Total Carbon Stranding Costs *(2020 $)*	$4.8 billion
Present-Value Carbon Stranding Costs *(2020 $)*	$3.3 billion
Present-Value Cost per Residential Duke Customer	$916.93

Notably, carbon stranding costs described above represent the total costs that ratepayers might be expected to pay for generation assets that would sit unused in order to avoid climate-related risks. The myriad other costs that would also be incurred in this scenario, including stranded transmission investments, costs for building zero-carbon replacement generation, additional operational costs as transitions occur years ahead of schedule, additional wear and tear on materials as the grid must reconfigure, and capital costs not directly associated with power plants that would need to be incurred to facilitate a transition to zero-carbon generation (e.g. new transmission lines), are not included. Therefore, the calculated 'carbon stranding' cost is only a part of the total cost burden for a disorderly transition to zero-carbon energy. However, these costs are unique in that they would be paid for assets that are neither used nor useful, and that Duke's ratepayers may be uniquely exposed to these costs.

E. Conclusion & Recommendations

This report began with an examination of the toolbox available to regulators as they work with vertically-integrated electric utilities to ensure the electric grid is planned and operated in the public interest. The fact is that many of these tools are not built for the 21st century. Assumptions about a steady environment for electricity and the continued dominance of conventional, fossil-fueled generations have been disrupted by the increasingly distributed and decarbonized grid unfolding across the world today.

Increased attention paid by financial institutions like the G20 and the Commodity Futures Trading Commission suggests that prudent management requires a risk-informed approach. While scientists, analysts, financers, and managers are still working to understand the dynamics of these risks, there is no doubt that they will have substantial, long-run implications for how we make decisions on a day-to-day basis. The climate risk template used by the TCFD provides a framework for this kind of future decision-making.

For reasons explored earlier in this report, Duke Energy's 2020 Integrated Resource Plan in the Carolinas represents an ideal case study for the incidence of climate risk. As Duke Energy faces pressure from increasingly affordable technology, ESG-interested shareholders, state policymakers, and an increasingly informed public tracking the corporation's climate commitments, these integrated resource plans simply must integrate climate-related risks in order to pursue the public interest for all stakeholders.

Based on the Plans' intended build-out of fossil generation without a clear plan or budget for decarbonizing these new plants in the future, there is reason to further investigate the incidence of these climate-related risks on utility's assets and operations. If Duke Energy has no plan or budget to decarbonize these plants, it may need to retire them early—creating 'stranded' costs as ratepayers pay for generation that is not in use. As decision-makers consider whether the Integrated Resource Plan is in the public interest, understanding the magnitude of these climate-related risks, including carbon stranding costs, is critical.

This report presents a high-level assessment of the magnitude of those risks, finding that 'carbon stranding' could cost ratepayers tens or hundreds of millions of dollars a year and as much as $4.8 billion over the next several decades. Notably, because this assessment does not include the cost of replacing stranded generation assets with zero-carbon generation, cost figures presented here are likely a substantial under-estimate.

To avoid these costs, utilities and their regulators can and should add new tools to their toolkit to ensure their planning decisions are prudent and in the public interest. This report concludes with a few recommendations for utilities and their regulators to integrate a climate-risk perspective into their planning activities.

For Regulators:

- Affirmatively find that climate-related costs are material to utilities' business operations, and that prudent management of the utility requires serious consideration of these risks.
- Identify management of climate-related risks through mid-century as a critical component of least-cost, just and reasonable integrated resource plans.
- Require integrated resources plans to include explicit consideration of climate risks.
- Add a requirement that utilities address their zero-carbon transition plans beyond the 15-year planning horizon, including a stranded asset screen and end-of-life plans for all existing and proposed fossil-fueled generation.
- Utilize the 'used and useful' test to lighten the burden on ratepayers for stranded assets.
- Reject integrated resources plans that do not adequately demonstrate that carbon-emitting assets will not be stranded midway through their engineering lifetimes.
- Integrate consideration of climate-related risks into assessments of whether individual projects meet the requirements for a certificate for public convenience and necessity.
- Reject applications for individual carbon-emitting generation assets that do not contemplate climate-related risks and a low-carbon transition.

Utilities:

- Incorporate climate-related risks and opportunities into decision-making at multiple levels in the organization, not just at the corporate officer level. Climate-related risks will be material and substantial whenever and wherever utilities are planning multi-decadal investments.
- Aim for complete transparency, not only to shareholders but to all stakeholders, regarding the exposure and magnitude of climate-related risks and opportunities.
- Invest in analytical capabilities to better understand the impacts of climate-related risks, both physical and transition, on the utility's assets and operations.
- Provide robust, transparent discussion of how current resource plans will be reconciled with net-zero carbon goals (including in cost projections and investment plans), as well as other climate-related risks. If additional zero-carbon retrofits are contemplated, budget for them within resource planning procedures. If stranding or accelerated depreciation is anticipated, include these costs.
- Present credible, long-term strategies for meeting carbon commitments as a part of demonstrating the prudence and necessity of new investments in generation.
- Continue policy dialogue with state policymakers on zero-carbon planning across the economy.
- Use a wide range of load forecast, resource deployment, and carbon pricing scenarios that allow for a robust consideration of the clean energy transition.

Appendix: Technical Specifications

This appendix summarizes the technical details of the emissions model used in this report.

The analysis projects carbon emissions from the fleet of large generation plants owned and operated by Duke Energy in the Carolinas. It shares similarities with other recent projections of carbon emissions and assessments of the implications of carbon constraints on the generation fleet from the University of Oxford Sustainable Finance Programme and Dr. Emily Grubert at tthe Georgia Institute of Technology.[117] This outline follows the broad outline of Saygin and Caldecott's 2019 study, which projects future emissions through 2050 for a generation portfolio given historical operation behavior, then models removal of units from the fleet in order to meet carbon constraints and estimates the costs of removing these units. In this case, a similar procedure is applied to Duke Energy's current and proposed generation fleet, as described in Duke Energy's 2020 Integrated Resource Plans.

Inputs for this analysis are generally taken from the Catalyst Cooperative's PUDL database, an open-source compilation of publicly available plant, unit, and utility-level data based on separate datasets from the Energy Information Administration, Environmental Protection Agency, and Federal Energy Regulatory Commission. Specific details on these inputs are provided below.

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[117] Deger Saygin, Jasper Rigter, Ben Caldecott, Nicholas Wagner & Dolf Gielen (2019) Power sector asset stranding effects of climate policies, Energy Sources, Part B: Economics, Planning, and Policy, 14:4, 99-124, DOI: 10.1080/15567249.2019.1618421; *and* Emily Grubert *et al 2020 Environ. Res. Lett.* **15** 1040a4.

i. Unit-level inputs and processing:

To assess current emissions and project future emissions, this analysis combines data at a unit and plant level.

Appendix Table 1: Unit- and Plant-level Data Inputs

Input	**Level**	**Source**
Capacity (MW)	Unit	EIA 860
Carbon Emissions (Metric Tons CO_2)	Unit	EPA Continuous Emissions Monitoring System
Plant Construction Year	Plant	FERC Form 1
Net Generation, 2016-2018 (MWh)	Plant	FERC Form 1
Capacity Factor, 2016-2018 (%)	Plant	FERC Form 1
Total Capacity Cost ($/MW)	Plant	FERC Form 1

To project future emissions from existing plants, this analysis uses average capacity factors (annual kilowatt-hours per kilowatt) and emissions factors (tons CO_2 emitted per net megawatt generated) 2016-2018. For projected new-construction units or units for which data was not available, this analysis uses fleet average capacity factors and emissions factors by technology (conventional steam coal plant, gas-fired combustion turbine, gas-fired combined cycle plant, gas-fired steam turbine, oil-fired turbine). Because gas-fired steam turbines and oil-fired turbines make up such a small portion of the total portfolio capacity, their capacity and emissions are not included in graphics in the report body.

Although this report generally treats generation units separately, it was not possible to estimate operation of combined-cycle gas plants if one unit was taken offline. Instead, each combined-cycle plant was treated as a single unit.

ii. Portfolio-level Inputs

Portfolio-level inputs are taken from the Duke Energy Carolinas and Duke Energy Progress 2020 Integrated Resource Plans, alongside other Duke inputs.

This model examines the Base Case with Carbon Policy for reference in terms of the timing and size of new generation investments, as well as retirements of existing plants. For plants not given an anticipated retirement date in the Integrated Resource Plans, this assessment used a baseline estimate of 40 years, consistent with the engineering lifetimes listed in the EIA's 2020 Annual Energy Outlook. To model the costs of new generation investments, the analysis pulls from research compiled as a part of EIA's Annual Energy Outlook. Based on the proposed or estimated lifetime, an annual depreciation or capital recovery factor—in terms of dollars per megawatt per year—is constructed.

Appendix Table 2: Portfolio-level Data Inputs

Input	**Source**
Intermediate 2030 Carbon Goal (50% by 2030)	2020 Duke Energy Integrated Resource Plan stakeholder materials
Timing and size of new generation investments	2020 Duke Energy Carolinas and Duke Energy Progress Integrated Resource Plan
Technical Specifications of New Investments	US Energy Information Administration Annual Energy Outlook
Unit Retirement Year	2020 Duke Energy Carolina and Duke Energy Progress Integrated Resource Plans; if not contemplated, assumed 40 years
Estimated rate of return on investment	Average of proposed rate of return on investment from most recent DEC and DEP rate cases in North and South Carolina
Additional capital expenditures	None. Only capital expenditures reported in FERC 1 and rate of return are included. Revenue requirements due to taxes, AFUDC, or CWIP are not included.

iii. Model Operation

Using unit-level capacity factors and emissions factors calculated as described above, this model calculates annual fleet-level emissions. As a point of validation, the emissions calculated by this model reasonably approximate DEC and DEP statements on fleet emissions. Moving forward year-by-year, the model calculates carbon emissions each year, adjusting as proposed generation comes online or existing generation reaches its planned retirement year or the end of its engineering lifetime. Outputs of this run of the model, called the "IRP case," are shown in Figure D-1 of the report body.

Next, the model creates a carbon constraint by linearly interpolating between projected 2020 emissions, Duke Energy's corporate goal of a 50 percent reduction from 2005 levels by 2030, and the Corporation's net-zero-by-2050. Three caveats should be noted: First, the constraint targets zero emissions in 2050 because of concerns with negative-emissions technology or offsets discussed in the report body. Second, this model assumes that Duke Energy plans to comply with its goals via a strict linear interpolation between targets. Third, the constraint assumes that Duke Energy Carolinas and Duke Energy Progress will hold to the same constraint as Duke Energy Corporation overall.

On the second run, the model applies this carbon constraint to annual emissions. If projected emissions are in excess of the carbon constraint for a given year, the model chooses a unit to downrate or retire. The heuristic for which unit to downrate or retire is as follows: First, it selects by technology (coal, then gas combined-cycle plants, then gas combustion turbines), then by emissions intensity. If any units have the same modeled emissions intensity, the unit with the earliest installation year is removed first. Downrated or retired capacity is then put in a "stranded pool" until the asset reaches its planned or estimated retirement year. The model moves sequentially, 2020-2050, continuing to remove units from generation as needed. For each year any capacity from a plant is in the "stranded pool," the model calculates the total amount of capital recovery or depreciation costs associated with stranded capacity. These annual and aggregate depreciation costs form the "carbon stranding costs" shown in Figures D-4 and D-5 in the report body. Although all capacity is either retired or stranded in 2050, projected or estimated lifetimes for several units extend into the 2060s and 2070s.

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