DUKE ENERGY'S 2023 NC CPIRP

An Analysis of Natural Gas Buildout Risks and Impacts on Residential Customers

July 2024

EQ Research

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Section I. Executive Summary & Key Findings

This report presents an analysis of Duke Energy's natural gas generation plans under its 2023 North Carolina Carbon Plan and Integrated Resource Plan (NC CPIRP) with the objective of providing greater transparency into the cost impacts and potential risks associated with those plans.[1] For simplicity, certain portions of the analysis that relate to rate impact quantification are limited to the North Carolina residential class, although the general findings are similarly, if not entirely, equally applicable to other customer groups. This report is organized into the following sections:

Section II: Summary of basic background information on Duke's natural gas generation buildout and the carbon emission limitations associated with federal regulations.

Section III: Evaluation of the potential costs and rate impacts associated with Duke's projected amounts of energy generation from natural gas units under both base and high natural gas price scenarios, and under a scenario of natural gas price volatility based on the most recent example of such volatility.

Section IV: Evaluation of the carbon emissions, costs, and rate impacts associated with Duke's planned new natural gas generation units from the standpoint of both fixed investment costs and operating costs, accompanied by discussion of the influence of state and federal carbon emission limitations.

Section V: Evaluation of potential stranded costs associated with the early retirement of planned new natural gas generation units due to carbon emission limitations under North Carolina H.B. 951 (2021).

Section VI: Summarized conclusions and takeaways.

Prior to presenting the analysis we believe it is appropriate to highlight several details surrounding its development that are important for proper interpretation of the findings.

1. This report is intended to provide greater transparency into the impacts and risks to residential ratepayers associated with Duke's natural gas generation plans. However, it should not necessarily be viewed as a critique of Duke's resource plan modeling, the accompanying assumptions, or an endorsement of any possible alternative resource portfolio.
2. This report is based on as-filed public NC CPIRP information and other publicly available data, which required the use of numerous assumptions and workarounds in the accompanying analysis.
3. Certain aspects of the analysis involve interpretations and accompanying assumptions relating to federal and state law which are not entirely certain.

[1] In the report we refer to Duke Energy's North Carolina subsidiaries collectively as Duke, and individually as Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP).

Appendix A: contains more detailed descriptions of these analytical notes in addition to other details of our methodology for different portions of this analysis. Notwithstanding these caveats, our analysis leads to the findings summarized below.

Rate Impacts of Varied Natural Gas Price Forecasts

Future natural gas costs play a prominent role in projections of the long-term costs of natural gas generation, and the cost impacts and price risks placed on customers scale directly in relation to a utility's reliance on natural gas generation (i.e., the percentage of the system energy mix). At the same time, forward price forecasts carry considerable uncertainty, in particular over the lengthy time horizons associated with the operating life of a typical generation unit (e.g., 35 years). For those reasons, we evaluated how natural gas generation costs would change under future conditions consistent with Duke's projected reliance on natural gas generation at both its base gas price forecast and its high gas price sensitivity scenario.

Our analysis indicates that for the period from 2024-2031, the high gas price scenario produces an aggregate incremental cost of $8.8 billion relative to the base gas price scenario across the Duke system (inclusive of all wholesale and retail loads in North Carolina and South Carolina). Of this amount, roughly $5.7 billion would be borne by North Carolina retail customers. If the time horizon is extended through 2038, the Duke system-wide cost increases to $25.8 billion, with $16.7 billion of this amount borne by North Carolina retail customers.

With respect to specific residential customer rate impacts, we estimate that in 2031 under Duke's base natural gas price forecast, a hypothetical DEC residential customer that uses 1,000 kWh/month will experience an increase in costs for natural gas as a fuel of $3.37/month (28.9%) relative to estimated 2024 fuel costs, while the same hypothetical customer of DEP will experience an increase of $13.15/month (87.4%). Under Duke's high natural gas price forecast, the monthly bill impact relative to 2024 costs at base natural gas price assumptions increases by $9.35/month for a DEC customer and $17.54/month for a DEP customer. These amounts translate to a 109% increase for a DEC customer and 204% increase for a DEP customer relative to 2024 costs at Duke's base forecasted natural gas prices.

Rate Impacts of Potential Natural Gas Price Volatility

Separate and apart from generalized long-term trends in natural gas prices, history has shown that natural gas prices are prone to volatility over shorter durations, ranging from weeks to months or years. Such volatility may arise from numerous causes (or combinations thereof), but regardless of the specific causes, instances of volatility are inherently unpredictable beyond the immediate future. Given the demonstrated risk of natural gas price volatility, and Duke's proposals to increase its reliance on natural gas generation, we evaluated the potential impacts of a volatility event on the costs of natural gas generation based on a scenario that mimics the price volatility that occurred primarily during 2021-2022 over a future two-year period running from September 2029 – August 2031.

Our analysis indicates that an event of gas price volatility similar to what occurred during 2021-2022 could produce incremental costs of $3.4 billion over two years at the Duke bulk system level, of which $2.2 billion would be borne by North Carolina retail customers. With respect to specific rate impacts, we estimate the additional costs to a typical residential customer of DEC that uses 1,000 kWh/month at $282 over two years, or an average of $141/year and $11.75/month. For the same hypothetical customer of DEP, we estimate the two-year incremental impact at $492, which equates to $246/year or $20.52/month. These additional costs translate to increases of 76.3% for a DEC customer and 70.2% for a DEP customer above monthly natural gas costs under Duke's base natural gas price forecast. Even relative to Duke's high natural gas price forecast, we estimate the incremental cost impact over two years at roughly $94 (a 16.8% increase) for a typical DEC residential customer and $134 (a 12.6% increase) for a typical DEP customer.

Rate Impacts of New Gas Generation

Total rate impacts of new natural gas generation consist of impacts associated with the recovery of fixed investment costs and costs of unit operation, the latter of which is driven by fuel costs. In our analysis the capital cost recovery portion for Duke's planned new natural gas generation units reaches a peak of $8.71/month in 2033 for a DEC residential customer that uses 1,000 kWh/month. For DEP, the peak residential rate impact for the same hypothetical customer is $2.90/month in 2031. Considering both fixed cost recovery and operating costs (at base projected fuel costs) of new units, we estimate a peak impact of $15.85/month in 2033 for the hypothetical DEC residential customer and $10.85/month in 2030 for the same hypothetical DEP customer.

Risks of Stranded Costs of New Gas Generation Investments

Electric rates include both costs resulting from the generation of electricity, called variable costs, and costs that do not change based on the amount of electricity generated, called fixed costs. Ratepayers are typically charged for the fixed costs of a power plant throughout the expected useful life of the plant even if that power plant is no longer being used to generate electricity or is only able to generate a fraction of its potential output. A portion of the fixed costs of such a power plant, become "stranded" because they have not been recovered by the time it is shut down. Stranded costs increase the average fixed cost of every MWh produced by a power plant because the same fixed costs are spread over fewer MWh. For instance, if a plant's lifetime is cut short by 50%, thereby reducing total generation by 50%, the per-MWh fixed cost doubles.

There are a variety of reasons why a power plant may retire early or otherwise be unable to generate the expected amount of electricity over its originally planned life. In regard to Duke's proposed new natural gas generation facilities, carbon emission limits under both state and federal law could result in significant reductions in electricity generation or even early retirement. Likewise, Duke's indicated plan to rely on co-firing hydrogen to reduce emissions in future years depends upon uncertain future hydrogen supply and price, as well as technological uncertainties such as whether a high-enough percentage of hydrogen can be co-fired with natural gas to meet emission limits.

Duke's proposed new natural gas plants that are planned to come online between 2029 and 2033 have an assumed lifetime of 35 years. If those plants are retired early at the end of 2050 to allow Duke to meet the state's net-zero carbon dioxide emissions target, ratepayers would still be potentially liable for $8.28 billion in stranded fixed costs after 2050. Another way to consider the impacts and risks of stranded costs is to compare the fixed cost portion of the levelized cost of energy (LCOE), which is a metric similar to the average cost in $/MWh over these plants' expected life. If Duke's proposed portfolio of new natural gas plants is retired early at the end of 2050 due to emission limits, hydrogen fuel constraints, or other reasons, the fixed-cost LCOE of the entire portfolio increases by about 30%.

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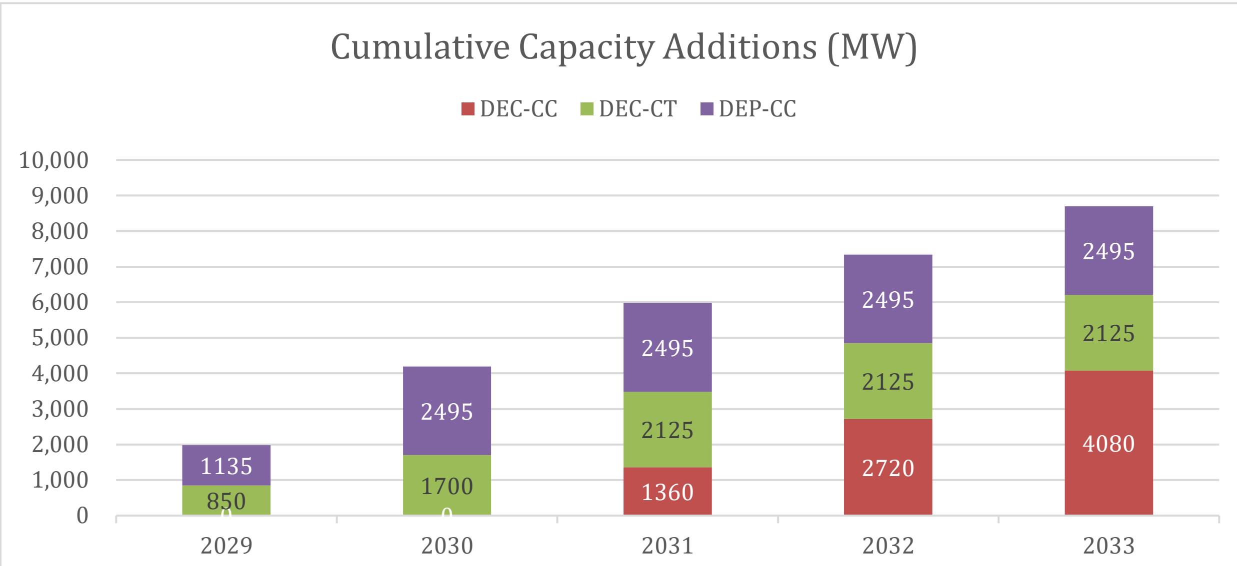
Section II. Introduction & Background

Duke's 2023 NC CPIRP update includes the proposed addition of 8,700 MW of new natural gas-fired generation by 2033. Of that total, DEC plans 4,080 MW of new combined cycle (NGCC) units and 2,125 MW of simple-cycle combustion turbines (NGCT), while DEP plans 2,495 MW of new combined cycle capacity, as shown in Figure 1 below.[2]

Figure 1 - Duke's Planned Natural Gas Capacity Additions



Duke's proposal for adding natural gas generation while also meeting carbon dioxide (CO_2) emission limitations relies on a strategy including a combination of co-firing low greenhouse gas (GHG) hydrogen and ramping down natural gas output to meet both the state emissions target and comply with then-proposed US Environmental Protection Agency (EPA) GHG-emission regulations.

Since Duke's proposal, the EPA issued its Final Rule[3] for New Source Performance Standards for Greenhouse Gas Emissions for new natural gas turbines which took effect on July 8, 2024. This Rule applies to all of Duke's proposed new natural gas units, and the EPA plans to develop an additional rule addressing GHG emissions from existing natural gas generating facilities. Although the EPA's Proposed Rule from May 2023 allowed for low-GHG hydrogen co-firing as an option for base-load units like NGCCs starting in 2032, revisions made in the Final Rule eliminated low-GHG hydrogen co-firing as a Best System of Emissions Reduction (BSER) pathway in the second phase, leaving 90% carbon capture and storage (CCS) as the only BSER

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[2] The DEP NGCC addition of 2,495 MW reflects 225 MW of capacity expected to be owned by the North Carolina Electric Membership Corporation (NCEMC) for the 1,360 MW unit expected to come on-line in 2029. This reduces DEP's 2029 NGCC capacity addition from 1,360 MW to 1,135 MW.

[3] 89 FR 39798, published May 9, 2024

pathway for units operating as base-load units (i.e., with a capacity factor greater than 40%) starting January 1, 2032.[4]

The removal of low-GHG hydrogen co-firing as a compliance option in 2032 and thereafter dictates that Duke's proposed NGCC units - which do not include CCS technology - will be restricted to operating at a 40% or lower capacity factor in nearly every year of their operating life. This results in those units generating roughly half of the electricity each year that an NGCC unit is capable of generating, although ratepayers would still be required to pay the same amounts towards the fixed investment costs. Although the reduction in generation also reduces GHG emissions, Duke's proposed portfolio of new natural gas generating facilities, with NGCC units operating at a 40% capacity factor starting in 2032, would still increase its North Carolina carbon dioxide emissions by about 8.76 million[5] short tons per year. With Duke's proposed natural gas buildout, operating in accordance with the EPA's Final Rule, Duke would have to reduce carbon dioxide emissions elsewhere in its system by a total of 27 million short tons, or 65.9%, below its 2021 emissions level to meet North Carolina's 2030 emissions target.

[4] 89 FR 39798 at 39802
[5] This emissions total does not include emissions attributable to the one NGCC unit planned to be located in South Carolina.

Section III. Natural Gas Price Risks To Residential Ratepayers

In resource planning, identifying the most cost-effective resource portfolio for meeting future customer electricity demands requires consideration of both upfront (i.e., fixed) investment costs and ongoing operational (i.e., variable) costs. Resource selection is also influenced by a multitude of other factors or constraints, but ultimately cost assumptions play a foundational role in determining the most appropriate future resource portfolio. Those cost assumptions create an inherent amount of uncertainty, and ultimately risk, that the selected portfolio could prove to be sub-optimal from the perspective of long-term costs.

Among all of these assumptions, of which there are many, future natural gas prices are typically among the most important cost factors given the pivotal role that natural gas prices play in determining the long-term costs of natural gas generation. At the same time, future natural gas prices are also among the least predictable aspects of resource modeling because they are vulnerable to major price swings due to factors that are inherently unpredictable beyond the very immediate future. The demonstrated history of natural gas price volatility accompanied by increased reliance on natural gas generation, as Duke contemplates, produces enhanced cost risk for customers.[6] History suggests that such volatility is an inevitable feature of natural gas prices that is disguised, and may not be accounted for, in the smooth curves of forward price projections.

In this Section we examine the potential impacts on residential customer bills of two distinct types of risks associated with Duke's plan for increased reliance on natural gas generation:

1. Natural gas prices that trend generally higher than the base price projections.
2. An instance of natural gas price volatility similar to what occurred during the period from September 2021 to December 2022.

Our analysis indicates that Duke's natural gas generation plans would considerably increase its energy reliance on natural gas generation through 2030-2031, and in doing so expose both DEP and DEC residential customers to additional fuel price risk under both of the above scenarios. However, such risks are not uniformly distributed across the respective utility service territories, with DEP customers facing significantly greater risk due to DEP's significantly greater reliance on natural gas, its relatively higher portion of sales attributable to the North Carolina residential customer class, and generally higher natural gas prices for DEP compared to DEC. We note here that for the purposes of this analysis we have not attempted to predict the effects of a merger of DEP and DEC into a single operating utility. That said, the predictable effect of such a merger would be to moderate impacts on DEP customers and increase them on DEC customers.

Estimated Residential Rate Impacts of Natural Gas Prices

Our analysis of residential rate impacts of future natural gas prices estimates monthly residential customer bills for each year from 2024-2038. The terminal year of 2038 reflects limitations on the availability of critical inputs (e.g., forecasted system and class-level energy needs, energy

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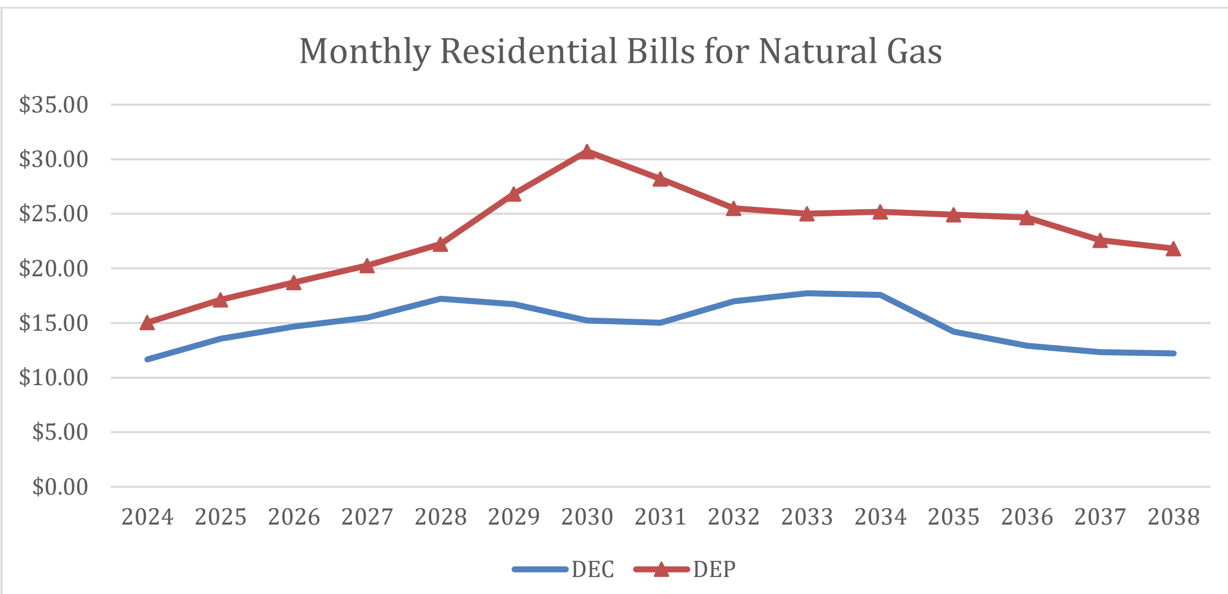
[6] We previously illustrated the increased role that natural gas generation has played in recent increases in residential customer rates in our April 2024 issue brief entitled *The Role of Fuel Costs in Duke Energy's North Carolina Rates*.

generation mix) in publicly filed materials, even though Duke's NC CPIRP extends through 2050. In addition, for a portion of our comparative analysis we use 2031 as the comparison year because, as discussed in more detail in Section IV of this report, new US EPA rules limiting carbon emissions from new natural gas generation (Phase 2 limits) become effective in 2032, which requires a significant change in assumptions on the operating capacity factors of new natural gas units.[7] Thus, our selection of 2031 as a comparison year is intended to eliminate the impact of such changed assumptions from the results. Nevertheless, we also present certain information on estimated impacts beyond 2031 given that the rate impacts of variations in natural gas prices will extend beyond 2031.

The starting point for our analysis of the residential rate impacts of natural gas prices is the projected impact using Duke's base natural gas price forecast. Figure 2 shows the impact of the base natural gas price forecast in the form of the average monthly amount of a customer's bill that is attributable to the costs of natural gas as a fuel for a customer that uses 1,000 kWh/month on average, from 2024-2038. The estimates presented in Figure 2 reflect all-in delivered costs inclusive of a premium relative to base commodity costs for costs associated with delivery, storage, and hedging, but do not include fixed plant investment costs or non-fuel O&M expenses.

Figure 2 - Forecasted Residential Impacts of Natural Gas Costs (Base Fuel Price)



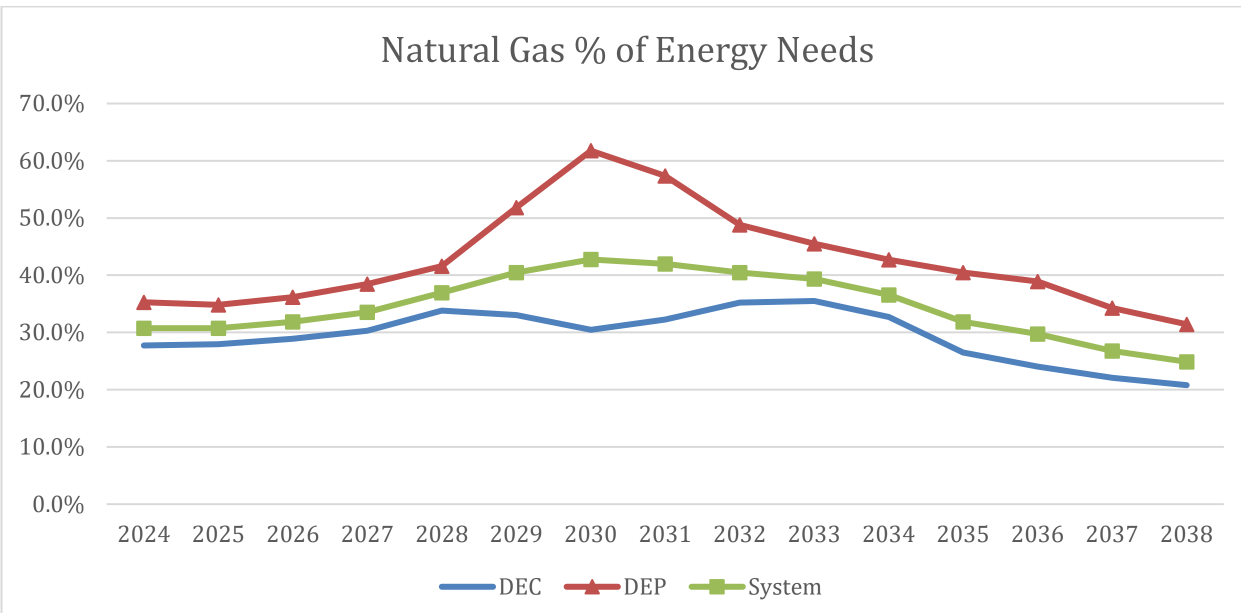
As illustrated in Figure 2, the rate impacts on DEC residential customers are considerably lower than those on DEP residential customers in general, which is attributable to: (a) the lower percentage of total system generation projected to come from natural gas[8], (b) the relatively higher percentage of DEP's energy requirements that are associated with North Carolina's

[7] Our assumption in this regard is that new NGCC unit capacity factors will be reduced from 80% to 40% to meet US EPA requirements. The reasons for this are described further in Section IV and various other assumptions in Appendix A.
[8] All other things being equal, a DEP customer would pay less in the form of non-natural gas fuel costs than a DEC customer.

residential customers compared to DEC's North Carolina residential customers, and (c) higher delivered natural gas prices for DEP compared to DEC relative to base market commodity prices.[9]

Figure 3 shows our estimate of the annual percentage of total generation expected to come from natural gas from 2024-2038 for DEC, DEP, and on a system-wide basis, which is helpful for understanding the temporal differences between the two utilities. As shown in Figure 3, Duke anticipates consistent moderate increases in natural gas generation through 2028, which are associated primarily with a combination of uprates to natural gas generation existing units and apparent increased dispatch compared to historic averages. A departure from this gradual trend occurs in 2029-2030 for DEP with the addition of large, baseload, NGCC units in both years, whereas DEC's natural gas penetration declines in 2029 and 2030 due to load increases that are not accompanied by an equivalent net increase in natural gas generation.[10]

Figure 3 - Duke's Future Reliance on Natural Generation



With this general backdrop in mind, Table 1 depicts our estimates of the monthly cost to residential customers of natural gas supply in 2031 compared to 2024 under base natural gas price assumptions, as well as the relative contributions of new natural gas generation units to these impacts. As illustrated in Table 1, under Duke's base natural gas price projections, natural gas costs have moderate impacts on DEC customers, an incremental cost of $3.37/month in 2031

9 DEP's actual incurred natural gas costs have historically been higher in relation to Henry Hub market prices than DEC's, meaning that DEP's delivered natural gas costs carry a higher "premium". Our analysis reflects a historic average of this premium. Future changes to regional supply and demand could plausibly affect the relationship between delivered natural gas prices and Henry Hub market prices, but we lack a reliable basis for making any such adjustments, in particular over the long-term time horizon associated with this analysis.

10 DEC's generation mix in 2029 and subsequent years is affected by the retirement of existing thermal units that use both coal and natural gas and the addition of significant new NGCT generation from 2029-2031. Assumptions used in our analysis due to a lack of specific data may affect the shape of the individual utility curves, but the System-wide curve is based directly on the materials that Duke presented in its filed NC CPIRP materials.

compared to estimated 2024 costs, which equates to an increase of 28.9% above 2024 monthly costs. For DEP customers, the 2031 impacts at base natural gas prices are considerably higher at $13.51/month and 87.4% relative to estimated 2024 monthly costs. As previously discussed, these amounts are based on a residential customer that uses 1,000 kWh/month on average. For customers with higher (lower) usage they would scale accordingly relative to the 1,000 kWh/month benchmark.

Table 1 - Typical Residential Bill Impacts of Natural Gas Costs (Base Fuel Price)

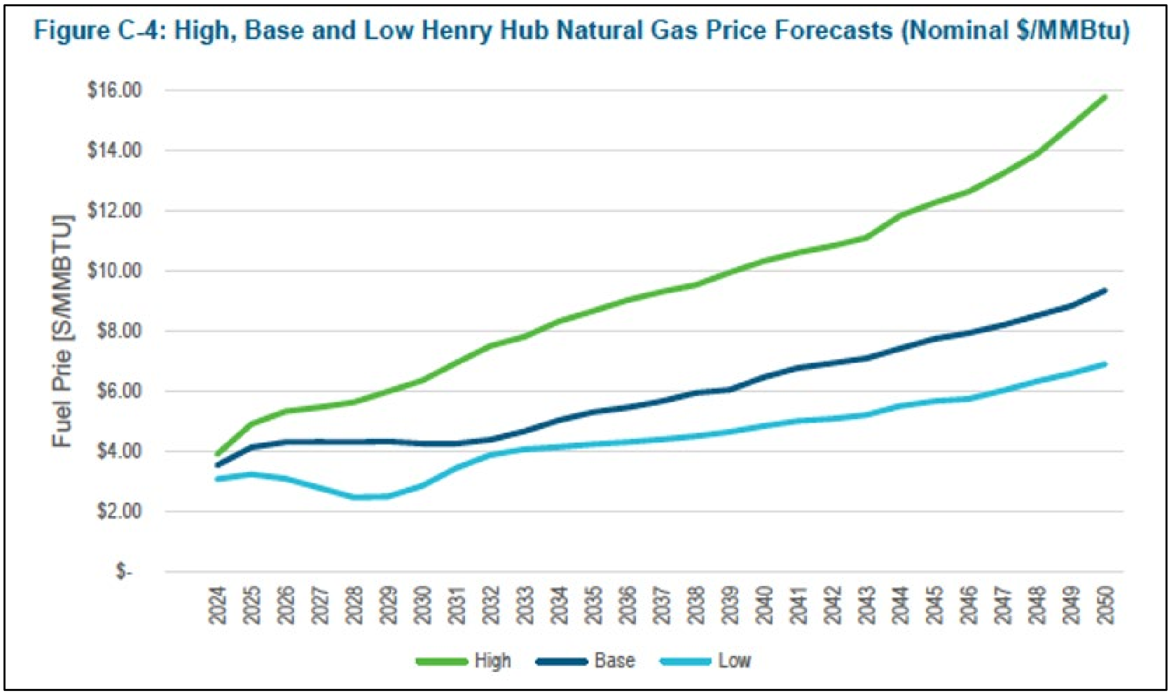
Descriptor	DEC	DEP
2024 Natural Gas Costs	$11.67	$15.04
2031 Natural Gas Costs	$15.04	$28.19
2031 Increase ($)	$3.37	$13.15
2031 Increase (%)	28.9%	87.4%
2031 Fuel Cost Increase Attributable to New Units ($)	$4.21	$10.06
2031 Fuel Cost Increase Attributable to New Units (%)	36.1%	66.8%

For DEC, the total increase is lower for all natural units than for only new units because generation from DEC's existing dual-fuel steam units decreases due to unit retirements and a greater quantity of new NGCC and NGCT generation comes online to replace this lost generation and meet increased load requirements. The lower residential rate impact for DEC also reflects the effect of system sales growing at a rate greater than North Carolina residential sales, which causes the North Carolina residential class to be allocated a lesser share of total fuel costs. Thus, even though our estimate shows total fuel costs increasing by roughly 64% from 2024 to 2031, the DEC North Carolina residential class allocation decreases from 25.5% in 2024 to 20.9% in 2031 (18%). In addition, residential retail sales still increase by roughly 4% over that time frame, resulting in a further lowering of the residential fuel cost rate since those costs are spread over a greater quantity of residential load.

The results for DEP differ significantly because: (a) DEP currently relies more heavily on natural gas generation and does not forecast any natural gas retirements during the 2024 to 2031 time frame, (b) both of DEP's new NGCC units are on-line by 2031 (i.e., the units primarily replacing the Roxboro coal plant), (c) the decline in the residential class share of load is not as large, and (d) DEP natural gas costs are generally higher than DEC's. As a result, the contribution from new units is only a portion of the 2031 increase and balance is associated with moderately higher natural gas costs and increased dispatch of existing units in order to meet projected load needs.[11] As we previously noted, it is important to keep in mind that the residential rate impacts described above reflect only fuel costs (not capital and non-fuel O&M costs) under Duke's base natural gas price forecast.

[11] Increased dispatch of existing natural gas units also increases costs because these units are less efficient than new units.

Figure 4 - Duke Natural Gas Price Forecasts



Through 2031, that base fuel price forecast only contemplates an increase of roughly 20% from 2024 prices, and largely flat prices from 2025 - 2031. Figure 4 above (sourced from the 2023 NC CPIRP) shows Duke's alternative natural gas price forecasts used in sensitivity scenarios.[12] Duke's high natural gas price scenario contemplates an increase of natural gas prices of roughly 95% from the base 2024 forecast through 2031.

Our analysis indicates that the cost associated with a high natural gas price scenario could be extraordinarily large. Table 2 shows our estimates of the aggregate incremental costs of a high natural gas price scenario by utility and on a system-wide basis through 2031 and 2038, as well as an estimate of the portion of costs that would be borne by North Carolina retail customers. The aggregate cost amounts shown on the first two rows of Table 2 are inclusive of costs assigned to South Carolina retail customers and wholesale customers in both North Carolina and South Carolina. The North Carolina retail cost impact estimates assume that North Carolina retail sales account for a constant percentage of total operating utility sales based on the energy allocators from their most recently filed cost of service studies.[13]

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[12] Figure 4 was extracted from sourced from Duke's August 2023 NC CPIRP filing (Appendix C, p. 44). We are aware that Duke used an updated forecast in its Supplemental January 2024 modeling, but the as-filed materials do not contain a representation of the updated forecast.

[13] These percentages are 67.26% for DEC and 61.78% for DEP, producing an overall weighted average of 64.44% for North Carolina retail customers through 2038, and 64.40% through 2031.

Table 2 - Aggregate Incremental Costs of High Natural Gas Price Scenario ($ Billion)

Time Horizon	DEC System	DEP System	Duke System
2024-2031	$4.2	$4.6	$8.8
2024-2038	$12.5	$13.3	$25.8
	DEC NC Retail	**DEP NC Retail**	**Duke NC Retail**
2024-2031	$2.8	$2.8	$5.7
2024-2038	$8.4	$8.2	$16.7

On an annual basis, the peak year for incremental costs would be 2033 for DEC ($1.44 billion), 2032 for DEP ($1.37 billion), and 2032 for the entire Duke System across North Carolina and South Carolina ($2.77 billion). The decline thereafter is attributable to total natural gas generation declining at a rate higher than the increase in the difference between prices under the base price and high price scenario.

Not surprisingly, the residential rate impacts of Duke's plans would also increase considerably if natural gas prices are higher than the base forecast. Table 3 presents our estimates of the residential rate impacts of natural gas prices using the high natural gas price curve in comparison to natural gas prices in 2024 in both the base and high price scenarios for all natural gas units (new and existing).

Table 3 - Typical Residential Bill Impacts of Natural Gas Costs – Base vs. High Fuel Price Curve

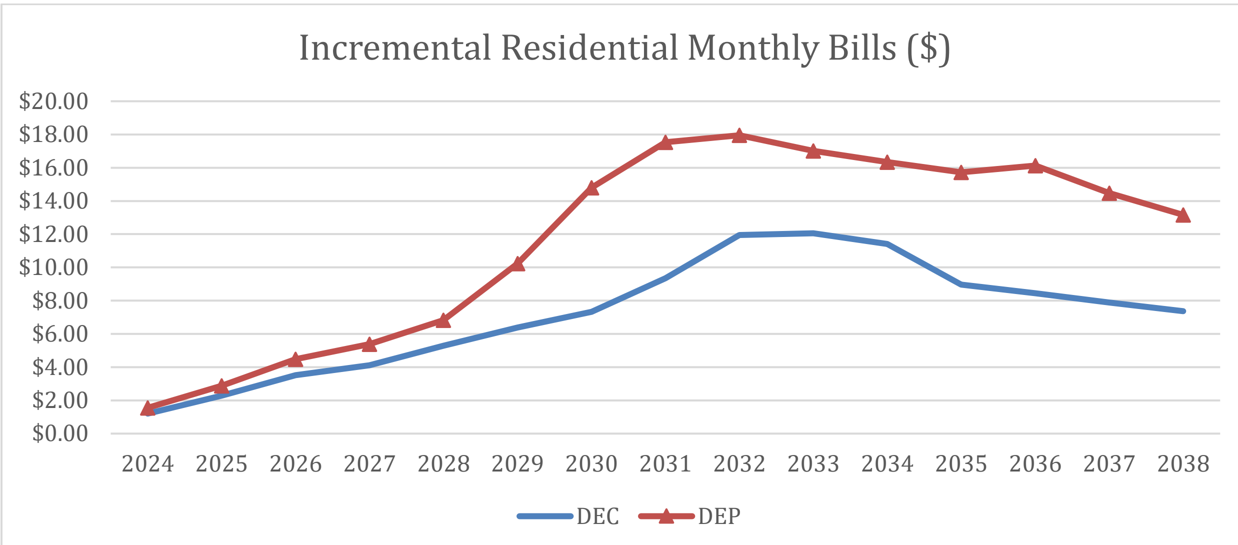
Descriptor	DEC	DEP
2024 Natural Gas Costs	$12.87	$16.60
2031 Natural Gas Costs	$24.39	$45.73
2031 Increase ($)	$11.52	$29.13
2031 Increase (%)	89.5%	175.6%
Incremental Impact of High Gas Price Scenario on Increase ($)	$8.15	$15.99
2031 Increase From Base 2024 Price Scenario ($)	$12.72	$30.69
2031 Increase From Base 2024 Price Scenario (%)	109.1%	204.0%

As illustrated in Table 3, all other things being equal[14], under a high natural gas price scenario in 2031 residential costs for natural gas as a fuel could more than double for DEC and triple for DEP relative to 2024 monthly costs. The difference between the two utilities is attributable to the same factors that we previously described as influencing residential rate impacts under a base fuel price scenario, including DEP's heavier reliance on natural gas generation and its generally higher natural gas costs compared to base commodity market prices.

[14] A change in unit dispatch in response to high natural gas prices would change these amounts, but it is not clear how much flexibility Duke would have to high natural gas prices with reduced natural gas dispatch of other available resources.

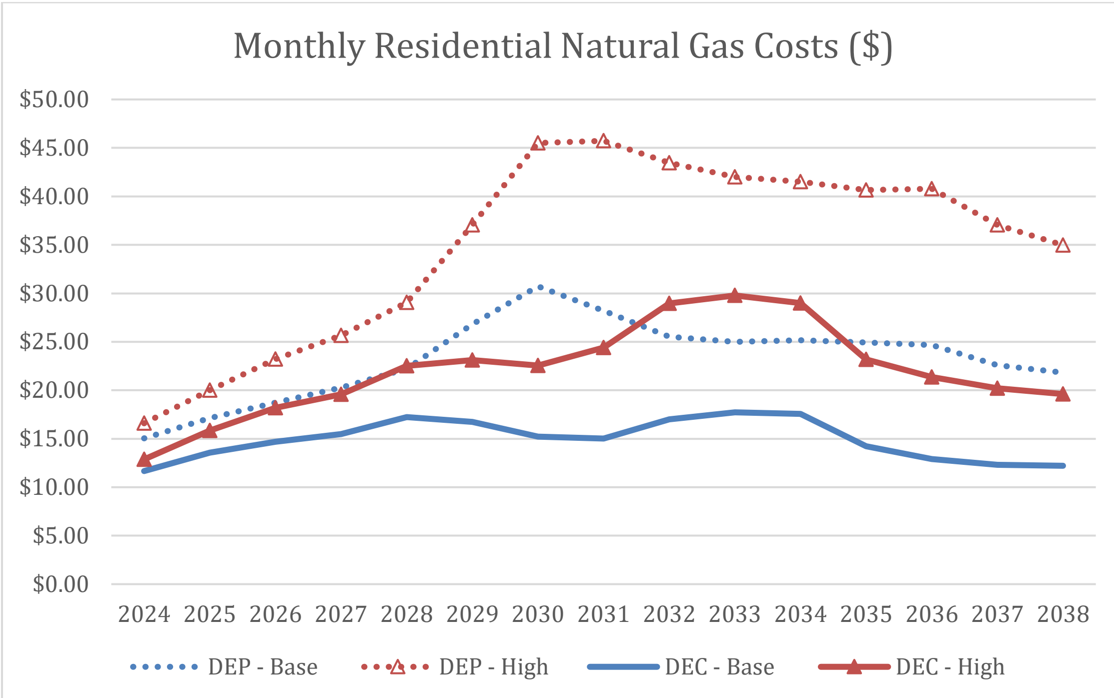
Of course, incremental rate impacts associated with high natural gas prices would not simply disappear after 2031. As we previously noted, our analysis indicates that ratepayer costs of natural gas would continue to increase through 2032 for DEP and 2033 for DEC before beginning to fall as a result of declines in natural gas generation amounts. Figure 5 shows our assessment of the incremental monthly bill impacts of a high natural gas price scenario (compared to a base price scenario) on residential customers from 2024-2038.

Figure 5 – Residential Bill Impacts of High Natural Gas Price Forecast vs. Base Forecast



The bill impact estimates on which Figure 5 is based indicate that for DEC, a high natural gas price scenario would increase residential customer bills in total by $474 from 2024-2031 and $1,291 from 2024-2038. For DEP we estimate the incremental costs at $764 from 2024-2031 and $2,094 from 2024-2038. Figure 6 depicts the annual variations in the difference between monthly residential natural gas costs under base price and high price scenarios for both DEC and DEP.

Figure 6 - Residential Bill Comparison – High vs. Base Natural Gas Price Forecast



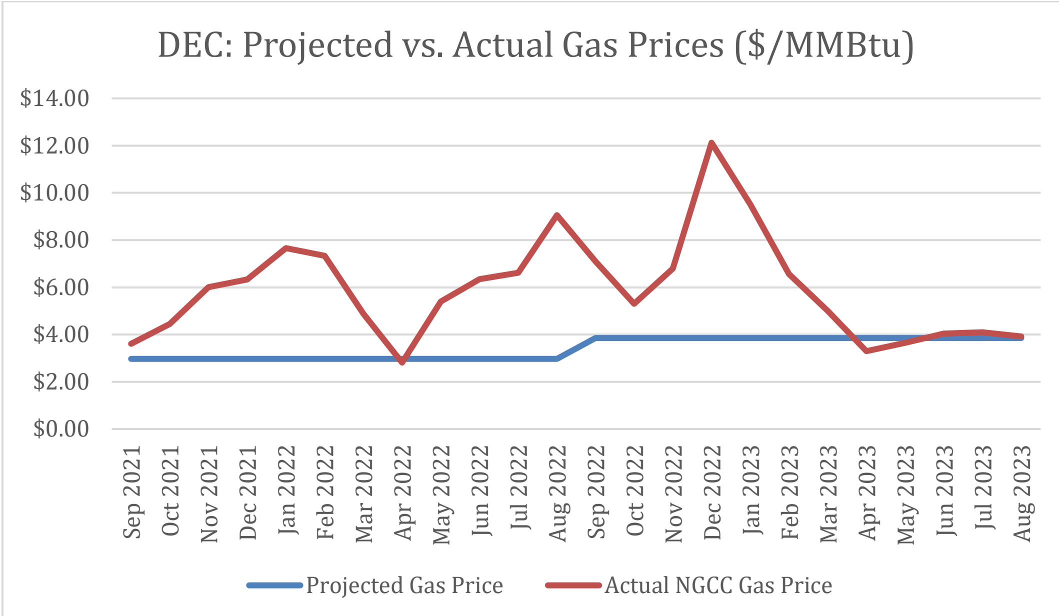
Estimated Rate Impacts of Natural Gas Price Volatility

Natural gas prices are affected by a number of factors over time horizons that can range in duration from weeks to months to years. Some variations, such as price increases during winter months due to increased heating demand, or near-term macro-economic effects, can have some level of general predictability. However, even in the near-term prices can be meaningfully affected by factors that are difficult or impossible to predict (e.g., extreme weather, transportation or storage disruptions, geo-political events) and in the longer term additional unpredictable factors may also come into play (e.g., inflation, other economic events). The smooth lines of forward price projections are not well-reflective of such price volatility in terms of both timing or magnitude.

In order to assess the risk to residential customers of natural gas price volatility we evaluated the "premium" associated with actual natural gas supply costs incurred by Duke during the most recent example of price volatility. Figure 7 shows the differences between DEC's forecasted natural gas costs in its annual fuel cost proceedings compared to actual incurred costs for the two-year period from September 2021 to August 2023.[15] In reality, market natural gas prices fell precipitously in January 2023, but Duke's incurred costs took several additional months to fully stabilize, presumably due to the lingering effects of forward purchases. The two-year time frame that we selected (ending August 2023) is intended to capture the effects of the tail end of the volatility period.

[15] While this graphic is limited to DEC, an equivalent graphic using DEP information would look virtually identical.

Figure 7 - Illustration of Gas Price Volatility



In order to assess the effects of potential natural gas price volatility, we analyzed how a similar event would affect the costs of natural gas for residential customers if such an event occurred from September 2029 - August 2031. This analysis is based on applying the same volatility shape as a percentage above the forecasted price to the projected natural gas prices (base and high) for that time period in its NC CPIRP.

Table 4 shows the results of this scenario in the form of aggregate cost impacts differentiated by operating utility and at the North Carolina retail level (i.e., excluding portions allocated to wholesale and South Carolina retail loads).[16] The amounts presented in Table 4 reflect differences between costs under a base forecasted natural gas price scenario and the gas price volatility scenario described above.

Table 4 - Aggregate Incremental Costs of Gas Price Volatility Scenario ($ Billion)

Cost Assignment Scope	DEC	DEP	Duke System
Operating Utility	$1.6	$1.8	$3.4
North Carolina Retail	$1.1	$1.1	$2.2

Figure 8 and Figure 9 show the results of this comparison on a monthly basis for DEC and DEP in the form of the residential rate/kWh of energy consumption.

[16] The North Carolina retail portion of these costs was estimated using a uniform percentage of North Carolina retail load by operating utility for each year, as previously described in our discussion of the incremental costs associated with a high natural gas price scenario. In aggregate, the North Carolina retail allocation of total Duke System costs is 64.31% for the gas price volatility scenario.

Figure 8 - Impacts of Potential Natural Gas Price Volatility (DEC)

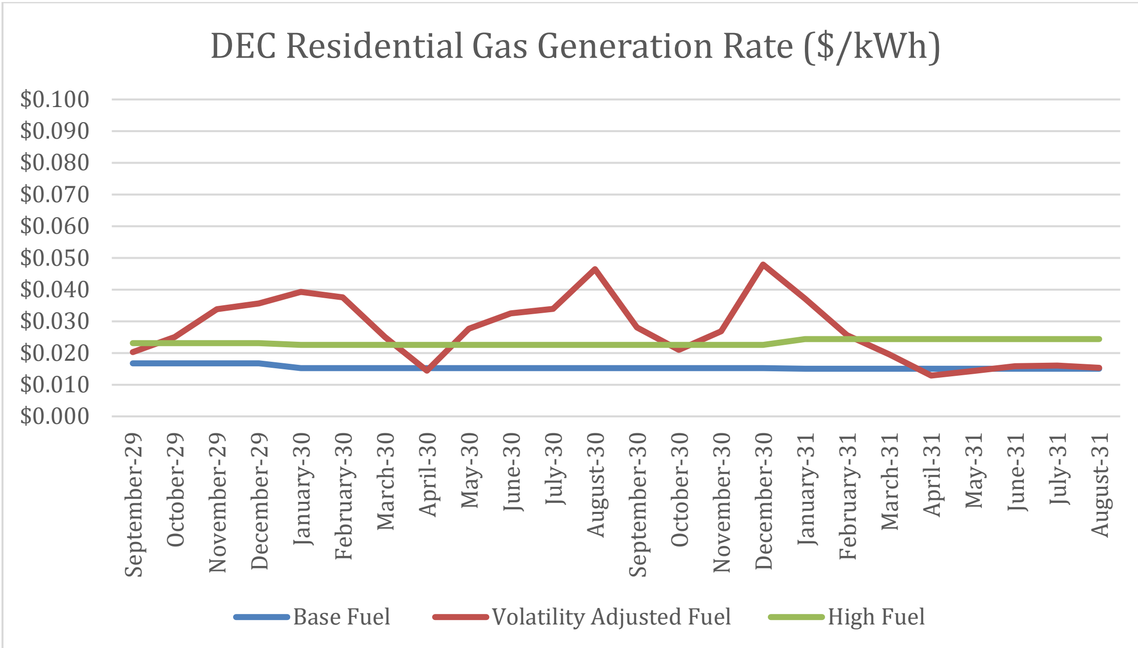
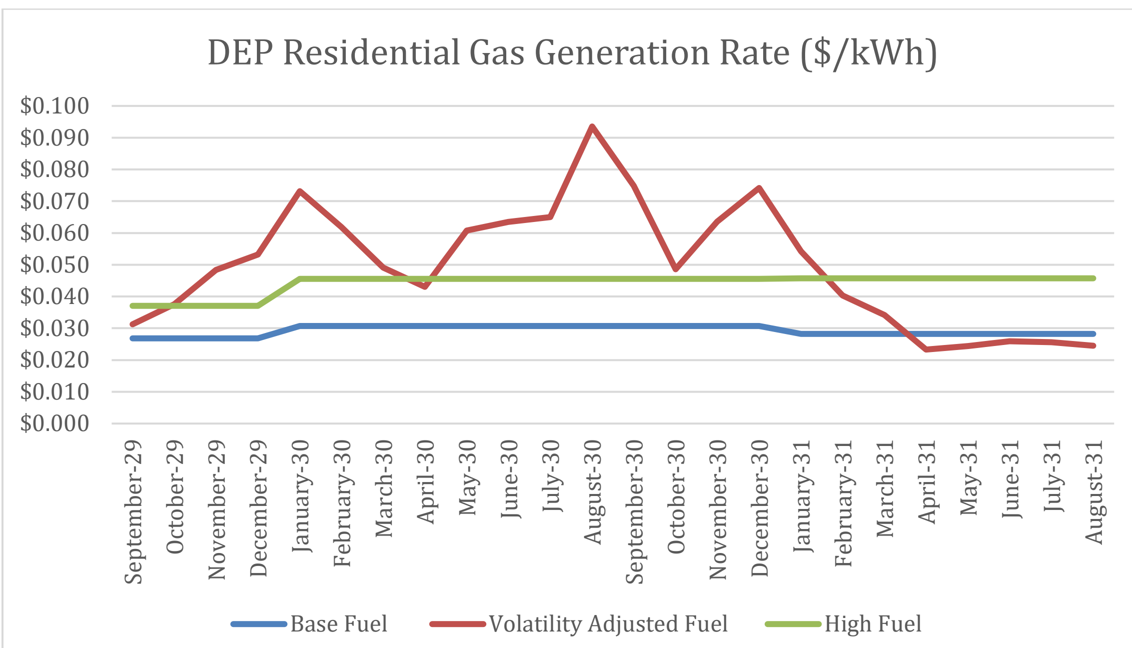


Figure 9 - Impacts of Potential Natural Gas Price Volatility (DEP)



As shown in Figure 8 and Figure 9, an event of natural gas price volatility from September 2029 to August 2031 equivalent to the volatility from September 2021 to August 2023 would produce significant adverse price impacts on residential customers of both DEC and DEP, even in relation to Duke's high natural gas price forecast.

Relative to base forecasted natural gas prices, our analysis of the potential impacts of natural gas price volatility indicates that a volatility event similar to what occurred during 2021 to 2023 could cost a typical residential customer of DEC that uses 1,000 kWh/month an additional $282 over two years, or an average of $141/year and $11.75/month. These additional costs translate to increases of 76.3% for a DEC customer and 70.2% for a DEP customer above monthly natural gas costs under Duke's base natural gas price forecast. Even relative to Duke's high natural gas price forecast, we estimate the incremental cost impact over two years at roughly $94 (a 16.8% increase) for a typical DEC residential customer and $134 (a 12.6% increase) for a typical DEP customer.

Section IV. Analysis and Impacts of GHG Emissions Limits

In this Section we examine Duke's plans for new natural gas plants in the context of carbon emission limits established by the U.S. Environmental Protection Agency (EPA) for new natural gas generation, as well as the CO2 emission reduction targets established by H.B. 951. Under H.B. 951, the NCUC must take all reasonable steps to reduce CO2 emissions from electric generating facilities located in NC to 70% below 2005 levels by 2030. Unlike the state target that is based on total emission levels, EPA's new regulations set a maximum emissions rate at the generation unit level in terms of pounds/MWh (lbs/MWh) of electricity generation and require new natural gas units operating as base-load units to employ 90% CCS as the Best System of Emissions Reduction (BSER) starting in 2032.

The results of our emissions analysis, as demonstrated in Figure 11, show the seemingly counter-intuitive result that EPA's new GHG emission regulations result in higher emissions than a scenario without those regulations. EPA's GHG regulations for new natural gas generators limit the capacity factor of Duke's proposed baseload NGCC units and in our analysis the reduced generation from new NGCC units is assumed to be provided by older less-efficient existing natural gas generation facilities which increases emissions when total required generation quantities are unchanged. There are multiple future circumstances under which this seemingly counter-intuitive result may not actually materialize, including but not limited to: potential future EPA regulations addressing emissions from existing natural gas units, or additional clean resources being added to Duke's resource portfolio.

H.B. 951 Emissions Reduction Target

Meeting the state's 2030 interim target limits Duke's total carbon dioxide emissions from N.C.-located facilities in 2030 and beyond to 22,759,556 short tons of carbon dioxide and requires Duke to achieve net-zero GHG emissions by 2050. Duke's 2021 carbon dioxide emissions were 41,003,085 short tons, or 18,243,529 short tons above the 2030 target. The 44.5% reduction below 2021 carbon dioxide emissions levels necessary for Duke to meet the state's 2030 target applies regardless of whether or not Duke ultimately builds new natural gas generation facilities.

EPA's Final GHG Rules for New Natural Gas Generators

Duke's proposed natural gas units are subject to the EPA's Final Rule[17] for New Source Performance Standards for Greenhouse Gas Emissions which is set to take effect on July 8, 2024. The Final Rule classifies natural gas generators into three categories based on the unit's actual generation as a percentage of its potential generation, also called the capacity factor. Low-load units used to meet peak demand – typically a simple-cycle combustion turbine – are defined as having a capacity factor of 20% or less. Combined cycle units are considered intermediate load units if operated with a capacity factor greater than 20% up to 40%, and baseload units if operated with a capacity factor greater than 40%. Units are classified based on their capacity

[17] 89 FR 39798, published May 9, 2024

factor for a given month and the same unit may be considered an intermediate-load unit one month and, if otherwise eligible, a base-load unit in a different month.

Duke proposed the Carbon Plan update before the Final Rule was published and the Final Rule has some key differences[18] from EPA's initial Proposed Rule.[19] Among the changes, EPA removed the proposed standards for existing natural gas units and indicated it plans to address those standards later. When, or if, EPA finalizes emissions standards for existing natural gas generating units, generation from Duke's existing facilities may be affected, but because the nature, timing, and extent of these potential future impacts is unknowable at present they are not considered in our analysis.

Another key change in the Final Rule was the removal of low-GHG hydrogen co-firing as a BSER pathway in the second phase, which leaves 90% CCS as the only BSER pathway for units operating as base-load units starting January 1, 2032.[20] This change, in particular, has significant implications for Duke's proposed natural gas buildout because low-GHG hydrogen co-firing was Duke's intended second phase compliance mechanism.

GHG Emissions

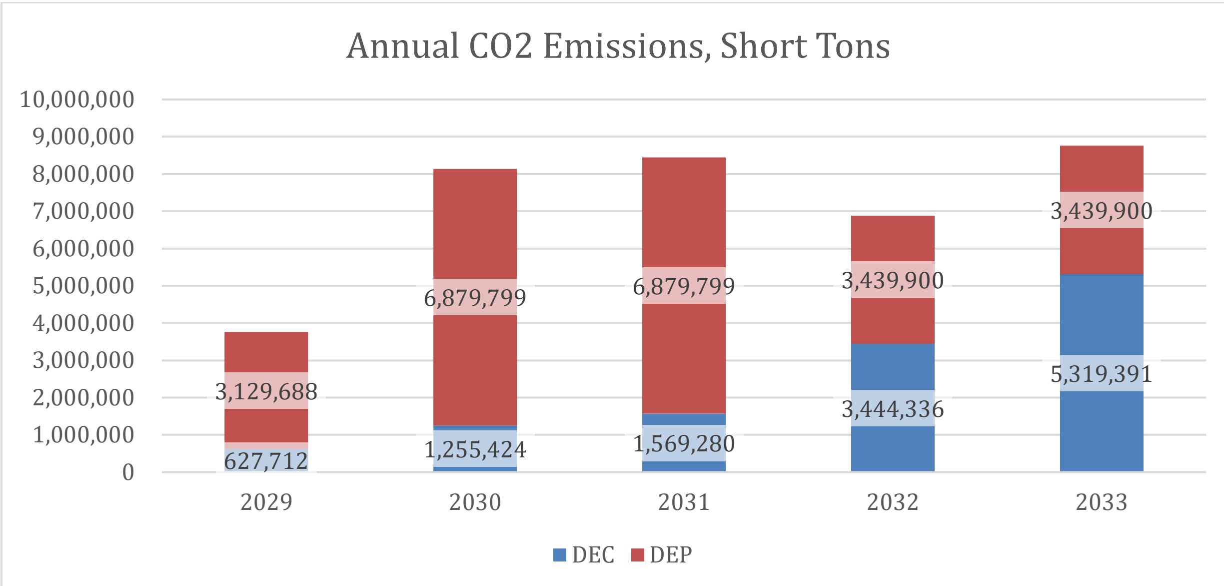
Our analysis of GHG emissions under Duke's proposed natural gas buildout includes two parts: the first is focused on quantifying emissions from the new proposed natural gas units under an operational scenario constrained by the EPA's recently finalized GHG emission regulations, and the second estimates total portfolio emissions through 2038 for plants located in NC.

This first portion of the analysis does not include a comprehensive evaluation of potential plant retirements or operational characteristics of Duke's overall generation portfolio. Under an operational scenario constrained by the EPA's recently finalized GHG emission regulations, each proposed NGCC unit is limited to operating at a 40% capacity factor starting in 2032 with natural gas consumption and emissions based on Duke's proposed heat rates and gross generation.

As shown in Figure 10, carbon dioxide emissions from new natural gas plants increase as additional plants are brought online. Emissions drop slightly in 2032 as capacity factor limits take effect and then increase as the final plants are brought online. Emissions in years after 2033 are assumed to remain the same for new natural gas units under a lowest-cost dispatch approach given that new units are more efficient than existing units and would be dispatched first.

[18] 89 FR 39798 at 39805
[19] 88 FR 33240, published May 23, 2023
[20] 89 FR 39798 at 39802

Figure 10 - Estimated Carbon Emissions From New Natural Gas Units Under EPA Regulations



By 2033, when all proposed plants are fully operational, Duke's proposed natural gas plants located in N.C.[21] will increase carbon dioxide emissions by a projected 8,759,291 short tons per year. In a practical sense, meeting the 2030 target set in H.B. 951 with these additional carbon dioxide emissions will require Duke to decrease carbon dioxide emissions elsewhere in its system by a total of 27,002,820 short tons, or 65.9%, below its 2021 emissions level.

State Emissions Target under HB 951

N.C.'s carbon dioxide emissions target set by H.B. 951 limits Duke's total carbon dioxide emissions from N.C.-located generating units in 2030 and beyond to 22,759,556 short tons of carbon dioxide. The 2023 NC CPIRP indicates that Duke would not achieve the 70% GHG emission reduction target until 2035 under the utilities' preferred scenario.

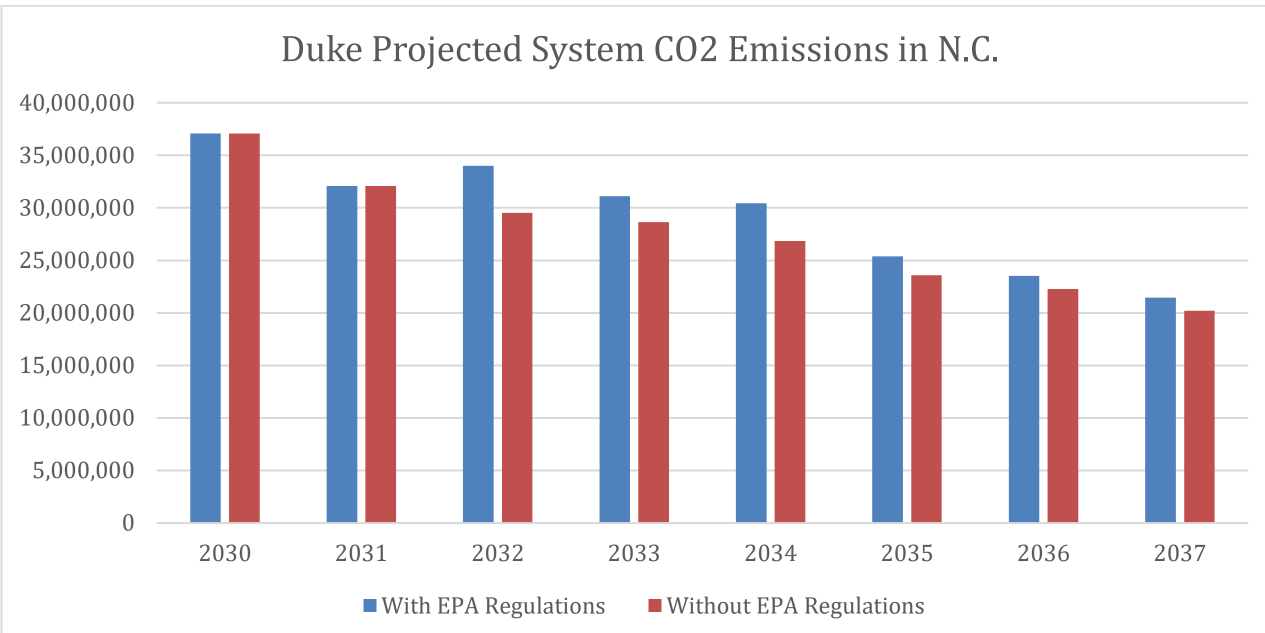
This second portion of our emissions analysis focuses on the period through 2038 for which some public data are available on Duke's systemwide fleet operations and expected load, and it specifically estimates Duke's N.C.-located[22] carbon dioxide emissions both with and without EPA regulations taking effect. Due to the complexity of dispatch models and limitations on publicly available data, our analysis adopted a high-level approach to estimating emissions based on generation needed to meet Duke's projected future load. We assume new natural gas plants will operate at their maximum possible level based on a least-cost dispatch approach because they are the most efficient in the fleet, and then reduced generation from the most emission-intensive sources in merit order to the extent possible in each successive year. Finally, we deducted emissions from new and existing plants located in South Carolina.

[21] DEC's first NGCC unit is expected to be located in South Carolina and emissions from that unit are therefore excluded from this H.B. 951-related emission projection.
[22] Emissions from Duke's three existing natural gas units located in South Carolina are not included in these totals.

As shown in Figure 11, under a scenario without EPA GHG regulations taking effect, similar to Duke's assumptions at the time of the proposal, the Company's carbon dioxide emissions in North Carolina continue to rise until 2030 and then begin dropping and reach a few percent above the target level under H.B. 951 in 2035. These reductions are mostly achieved by the retirement of dual-fuel units and the reduction of output from existing NGCC units as new NGCC units come online.

However, under a scenario in which EPA regulations do take effect, Duke's proposed new NGCC units' output is significantly reduced as a result of the capacity factor limits for new non-CCS units. The result is a potentially delayed retirement of dual-fuel units and less substitution of generation from existing NGCC units by new NGCC units, as well as a delay of a couple of years in Duke reaching the H.B. 951 target.

Figure 11 - Duke System CO2 Emissions in N.C.



Rate Impacts of Fixed Costs

Our analysis of rate impacts is focused on Duke's plan as proposed, based on heat rates and capital costs for the NGCC units along with its discussion of hydrogen co-firing, as Duke's proposal does not include CCS NGCC units. The result is that Duke's NGCC units, as proposed (i.e., without CCS), would be restricted, likely by a permit condition, to operating at a capacity factor of 40% or less starting in 2032 because hydrogen co-firing is no longer a BSER pathway for base-load units.

Effectively, the 6,575 MW of new NGCC capacity proposed by Duke - 75.6% of total proposed capacity - would be limited to only generating about half the electricity it would be technically capable of producing starting in 2032. Our analysis accounts for this restriction by reducing the capacity factor of each new NGCC unit to 40% starting in 2032. Such a reduction in operation has (at least) two significant impacts:

- Variable operating and fuel costs for the new NGCC plants decrease due to the reduced output starting in 2032 but would likely need to be made up for by higher-cost generation from older less-efficient plants.
- The fixed investment costs for new NGCC units are spread over fewer kWh of generation, increasing the cost per kWh attributable to fixed costs. For example, a fixed cost of $0.01/kWh for a plant operating at an 80% capacity factor would be a fixed cost of $0.02/kWh for the same plant operating at a 40% capacity factor.

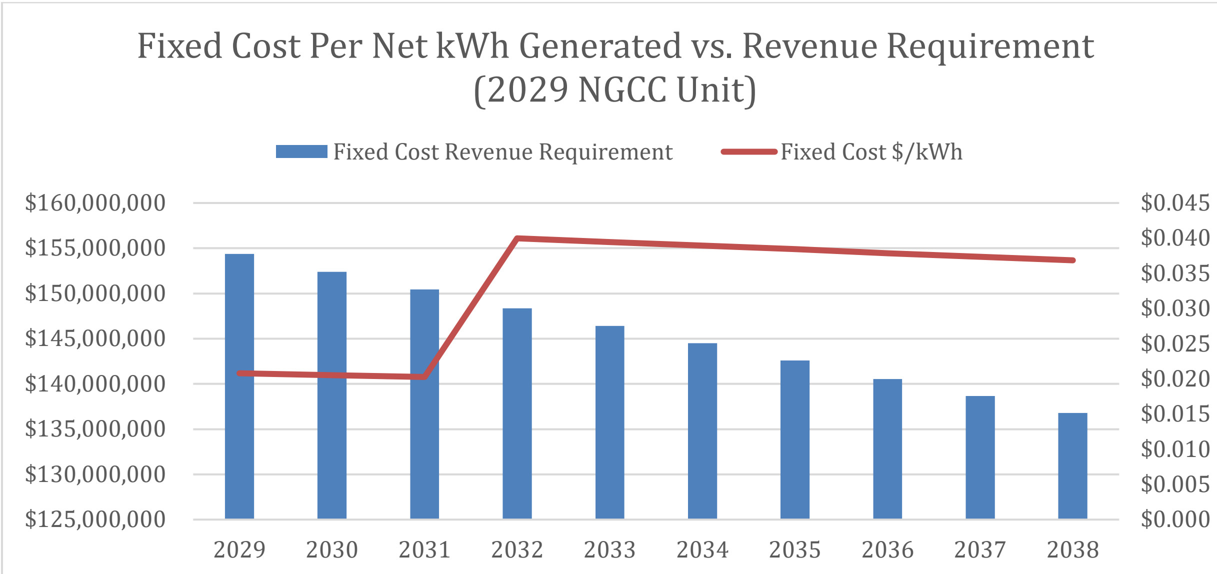
Fixed costs include annual expenses that do not change based on how much electricity a generating unit produces, and these include expenses such as annual depreciation, interest paid on debt, return on shareholder equity, taxes, and fixed operations and maintenance costs. The rate impacts, in $/MWh, of fixed costs decrease as more electricity is generated because the same total cost is spread over a larger number of MWh sales. This relationship is defined by the capacity factor of a generating unit as a higher capacity factor means the unit is generating a higher percentage of its maximum potential output.

There is a tradeoff between the operating costs and fixed costs of generating units designed to serve different segments of system loads (i.e., base, intermediate, peak). Generators such as NGCC units have higher fixed costs than NGCT units. Duke's per-MW mid-range capital cost estimated for NGCC units in 2023$ is 24.2% higher than its estimate for NGCT units. However, the higher fixed cost of an NGCC unit is offset by its increased efficiency and lower operating costs, about 30% lower for NGCC units than for NGCT units in Duke's estimate. The higher operating efficiency offers additional savings because NGCC units typically serve base or intermediate load and operate for several times the number of hours in a year than NGCT units which are typically intended to serve peak load needs.

As discussed in the previous section, the rate impact of fixed costs varies inversely in proportion to a unit's capacity factor. If a generating unit's capacity factor decreases by half, then the fixed cost portion of rates attributable to that unit doubles. Figure 12 demonstrates the impact on rates that results from ramping down an NGCC unit that began operations in 2029 and operated at a typical 80% capacity factor from 2029-2031 to the 40% capacity factor that would be required under EPA regulations since the unit does not have CCS technology.

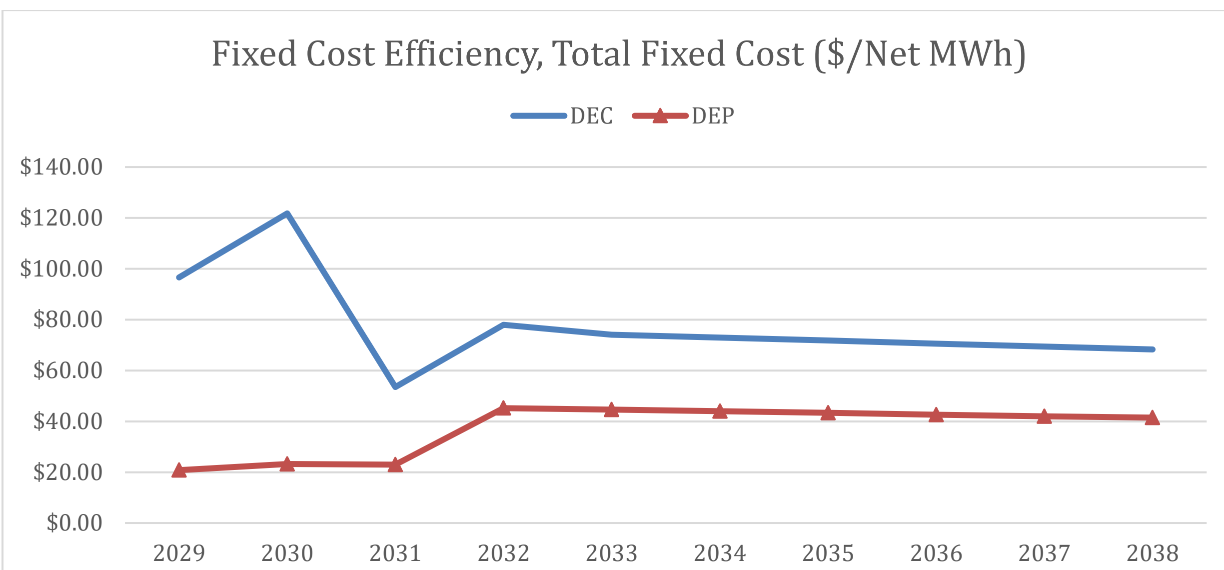
As shown in Figure 12 the total annual revenue requirement attributable to fixed costs for the unit steadily declines in each year as depreciation reduces the unit's book value and, in turn, interest expense, returns on shareholder equity, and taxes. However, the unit's capacity factor drops from an estimated 80% to 40% in 2032, which reduces net electricity generation at retail meters from 7,421,793 MWh in 2031 to 3,710,896 MWh in 2032 and thereafter. This reduction in output increases the fixed cost per net kWh from the unit from about $0.02/kWh to about $0.04/kWh. It also changes the ratio of per-kWh fixed-to-variable costs, with the fixed cost portion of the unit's output rising from 36.8% per kWh in 2031 to 70.6% per kWh in 2032.

Figure 12 - Fixed Cost/Net kWh Generated Vs. Revenue Requirement



Overall, the total fixed costs per net MWh of Duke's proposed portfolio of new natural gas generation reflect the lower capacity factors of NGCC units starting in 2032. As shown in Figure 13, DEC's portfolio cost per net MWh in 2029 and 2030 is considerably higher than DEP's because DEC plans feature 1,700 MW of NGCT capacity by 2030 while DEP plans 2,495 MW of NGCC capacity by 2030.

Figure 13 - Efficiency of Fixed Cost Incurrence

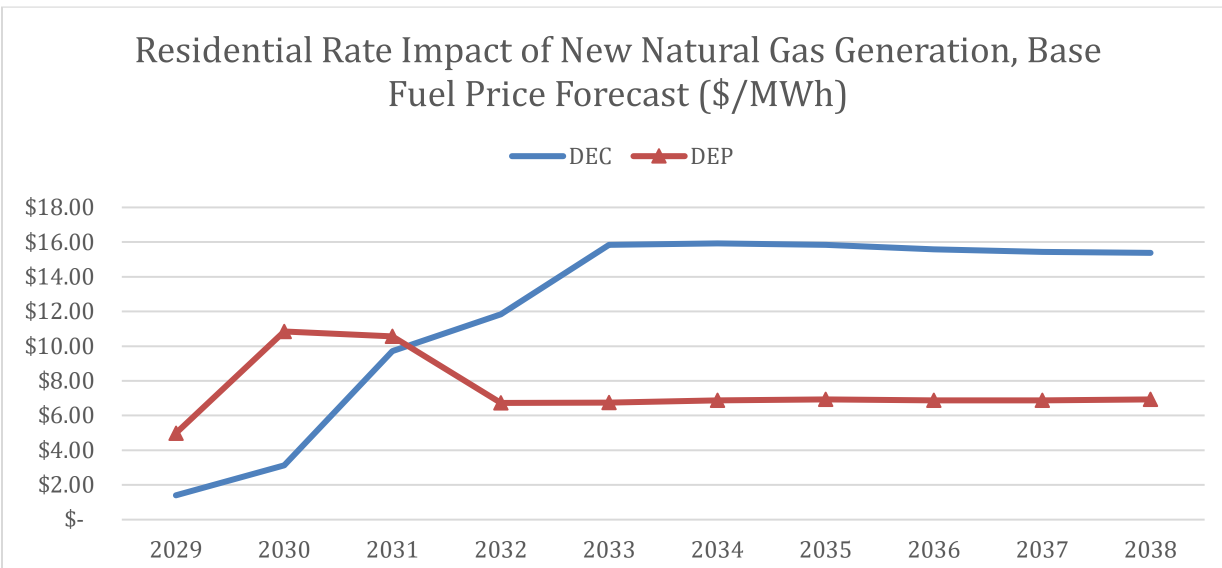


The two operating utilities' per-MWh fixed costs are more similar in later years as DEC adds additional NGCC capacity, although DEC's NGCT units continue to result in slightly higher per-MWh fixed costs on a portfolio basis. The fixed cost impacts on customer rates will reflect these trends based on the manner in which costs are allocated by customer class. Lower NGCC unit capacity factors starting in 2032 significantly increase the fixed cost portion of the proposed new natural gas portfolio in rates - an effect that will persist for decades regardless of how much electricity these facilities actually generate.

Overall Residential Rate Impacts

Our analysis projects the annual revenue requirement from Duke's proposed new natural gas generation facilities, including the increase allocated to residential customers, and separately evaluate the projected increase in total natural gas fuel costs. The estimated impact on residential rates in 2033 from Duke's proposed natural gas buildout is approximately 1.6 cents/kWh for DEC customers and 0.68 cents/kWh for DEP customers, as shown in Figure 14. This estimate includes both fixed and variable costs (based on Duke's base fuel price forecast) and assumes Duke's proposed NGCC units operate in compliance with EPA regulations.

Figure 14 - Total Costs of New Natural Gas Generation



Considering the range of future natural gas fuel prices presented by Duke, residential customers of DEC would see an increase in overall rates between 1.5 and 2 cents/kWh purchased in 2033 and residential customers of DEP would see an increase in overall rates between 0.6 and 0.9 per kWh purchased in 2033, attributable solely to the new natural gas plants without consideration of other impacts in Duke's overall generation portfolio, as shown in Figure 15 and Figure 16 below. These estimates of future bill impacts do not include the cost of generation from less-efficient existing sources that would likely be required to compensate for the reduced capacity factors of Duke's proposed NGCC units post-2032, nor do they include any cost estimates associated with the use of CCS technology or low-GHG hydrogen co-firing.

Figure 15 - New Natural Gas Generation Impacts - DEC

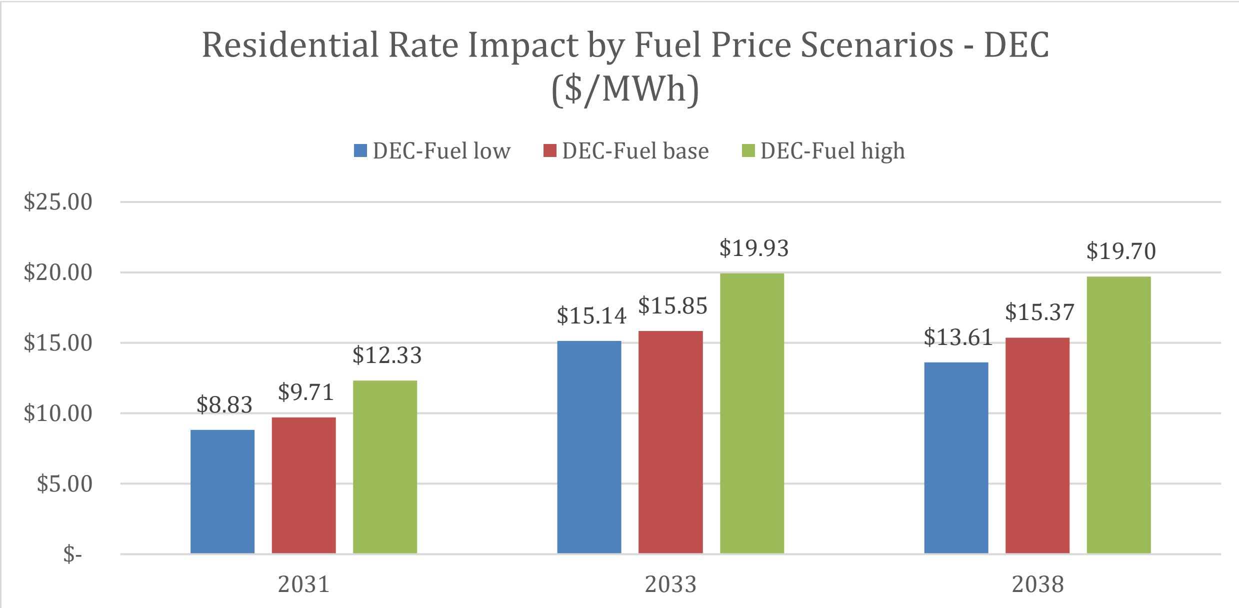
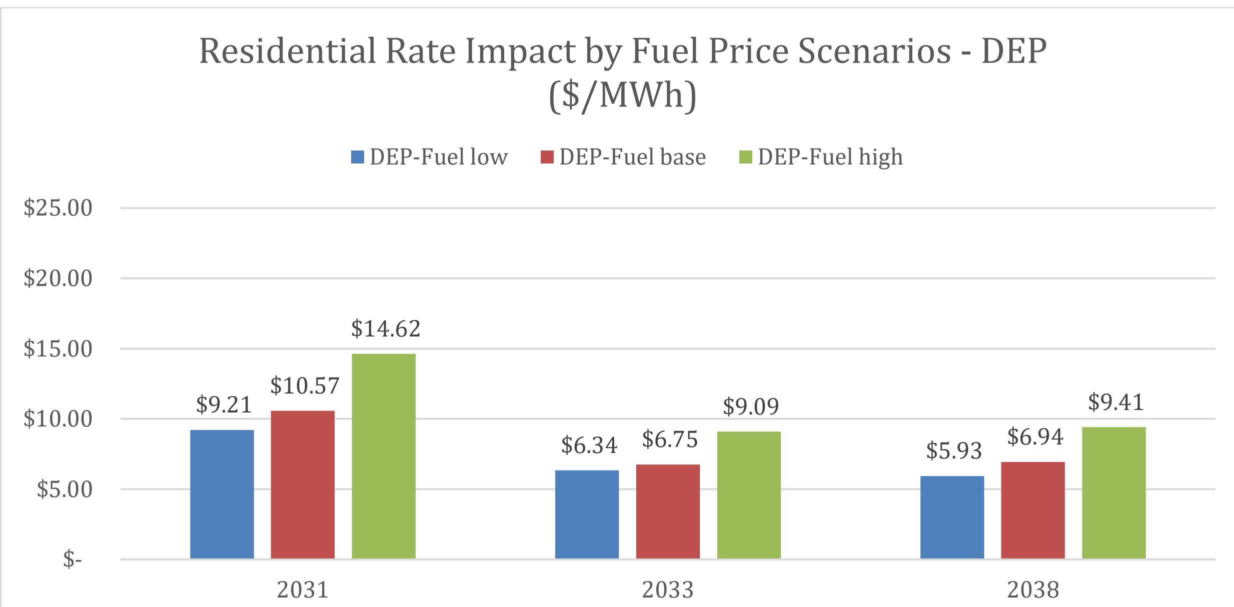


Figure 16 - New Natural Gas Generation Impacts - DEP



For a residential customer that uses 1,000 kWh/month, these rate impacts translate to the monthly bill impacts shown in Table 5. As shown in Table 3 and the prior figures, the pattern of bill impacts differs between DEP and DEC due to the total amount and timing of natural gas resource additions and the breakdown of new generation between NGCC and NGCT units. The rate impacts fall for DEP starting in 2032 as a result of the reduced capacity factor for new NGCC units (i.e., lower fuel costs), all of which are in service by 2031. However, for DEC the impacts increase from 2031 to 2033 despite this effect because: (a) a portion of the rate impacts are associated with NGCT units, and (b) the addition of NGCC units in both 2032 and 2033.

Again, we note that the amounts in Table 5 do not include a cost for replacement energy or capacity that might be needed due to reduced dispatch of NGCC units starting in 2032.

Table 5 - Monthly Residential Bill Impacts of New Natural Gas Units

Year	2031	2033	2038
Duke Energy Carolinas			
Low Fuel	$8.83	$15.14	$13.61
Base Fuel	$9.71	$15.85	$15.37
High Fuel	$12.33	$19.93	$19.70
Duke Energy Progress			
Low Fuel	$9.21	$6.34	$5.93
Base Fuel	$10.57	$6.75	$6.94
High Fuel	$14.62	$9.09	$9.41

Hydrogen and CCS Options

A transition to hydrogen fuel was a critical element of Duke's plans to build new natural gas generation while at the same time reducing and eventually eliminating carbon emissions from those same units. The EPA's new regulations still allow for the use of hydrogen to meet operating limits on GHG emissions on a per-MWh basis or for other reasons (e.g., to meet the state's 2030 carbon dioxide emission target), but new NGCC units operated with a capacity factor above 40% are still required to use CCS technology starting in 2032.

The use of hydrogen is not considered in our analyses because using hydrogen is no longer a BSER option for compliance with EPA regulations. However, hydrogen may still have a role in reducing total system emissions and meeting the state's carbon dioxide emissions target. To the extent that hydrogen has a place in Duke's future plans, it must be noted that hydrogen production, particularly zero-carbon hydrogen, primarily occurs on a small scale at present and that there are high levels of uncertainty regarding the timing, costs, and availability of hydrogen fuel in the quantities necessary to meaningfully impact GHG emissions from Duke's proposed new natural gas plants.

As previously mentioned, the only compliance option for new natural gas plants operated as a base-load unit (i.e., capacity factor above 40%) under the EPA's Final Rule is the use of CCS technology. Although Duke did not include cost estimates for NGCC units with CCS technology in the NC CPIRP, the National Renewable Energy Laboratory's 2023 Annual Technology Baseline (ATB) provides some basis of comparison. According to the ATB, without including capital or fixed costs for carbon dioxide transportation or storage, capital and fixed costs for NGCC units with CCS technology are projected to be about twice the cost of NGCC units without CCS technology, and NGCC units with CCS technology are estimated to operate with a heat rate about 10% higher (i.e., 10% less efficient) than comparable NGCC units without CCS technology.

Section V. Stranded Cost Analysis

EQ conducted supplemental analyses to examine the risk of stranded costs in the event that Duke's proposed new natural gas plants only generate electricity through 2050. Although this is a hypothetical scenario, a combination of factors and trends such as decarbonization of the electricity sector, future natural gas prices, potential future carbon emission pricing, reduced costs in non-fossil fuel generation technologies, among others, make a future scenario in which some or all of Duke's proposed natural gas plants do not operate for their full 35-year expected life.

Stranded costs are a risk to ratepayers because even if the generating plants are retired and stop generating electricity, utilities are generally allowed to recover their investment and investment-related costs through rates. There are a variety of mechanisms through which this cost recovery may be accomplished, which may include recovery of remaining post-retirement costs and investments over a different time period than may be remaining in a plant's 35-year assumed useful life and refinancing of debt or securitization of remaining asset values that may alter the cost of debt and return on equity associated with one or more plants.

In our analysis, we assume post-retirement recovery of remaining investments and investment-related costs from 2051 onwards follows each plant's original timetable at the cost of debt and return on equity applied throughout the plant's life. Post-retirement costs include annual depreciation expense, interest on debt, return on equity, and tax expense; exclude fixed O&M expenses and all operating expenses; and no expenses associated with decommissioning or site remediation are included.

Stranded Costs from Early Retirement

The first of Duke's proposed new natural gas generating facilities planned to come online in 2029 would be fully depreciated after 35 years by the end of 2063, while the last generating facility would come online in 2033 and be fully depreciated by the end of 2067. If these facilities were retired at the end of 2050, ratepayers would only benefit from their electricity generation for about 50%-60% of these plants' useful lives but would still pay the full cost of building these plants.

Revenue Requirement Impacts - Portfolio

The first part of our analysis of stranded costs resulting from early retirement of these plants at the end of 2050 focuses on revenue requirements associated with the fixed investment-related costs of these proposed plants. This component of the analysis examines the remaining asset values at retirement and annual investment-related expenses in years after 2050 under a scenario where fixed-cost recovery continues unchanged following these plants' retirement at the end of 2050.

At the end of 2050, Duke's proposed natural gas plants have a systemwide total remaining book value (i.e., undepreciated value of the generating facilities) of $5.03 billion, of which nearly $3.93 billion is attributable to DEC and about $1.11 billion is attributable to DEP. As shown in Table 6, the undepreciated portion of the capital investment remaining at the end of 2050 represents 42.9% of Duke's combined investment, 44.2% of DEC's investment, and 38.9% of DEP's investment.

Table 6 - Remaining Book Value and Fixed Costs Recovery with 2050 retirements

	DEC	DEP	Total
Book Value, end of 2050	$ 3,926,979,689	$ 1,105,346,792	$ 5,032,326,480
Combined Starting Book Value	$ 8,885,367,182	$ 2,843,545,531	$ 11,728,912,714
% of Starting Book Value, end of 2050	44.2%	38.9%	42.9%
Total Fixed Cost Recovery after 2050	$ 6,561,045,954	$ 1,721,128,654	$ 8,282,174,608

Although the combined undepreciated book value of Duke's proposed natural gas facilities at the end of 2050 is just over $5 billion, ratepayers will continue to be charged for the annual depreciation expense, interest expense, return on equity, and taxes associated with these plants through the end of each plant's 35-year life - 2067 for DEC and 2064 for DEP. The total amount of stranded costs to be recovered in rates associated with fixed investment-related expenses after 2050 is $8.28 billion if these proposed natural gas plants are retired early at the end of 2050 and recovery of fixed costs continues on schedule through the end of each plant's 35-year depreciable life.

Revenue Requirement Impacts – Individual Facilities

The contribution of individual generating facilities to the total portfolio-level stranded cost varies based on a combination of each facility's initial cost, or starting book value, and the year in which the facility began operations. The following tables (i.e., Table 7, Table 8, and Table 9) provide a breakout of stranded fixed costs[23] for each proposed facility based on early retirement at the end of 2050.

As demonstrated, NGCT units have lower capital costs and represent a smaller portion of the total portfolio. DEC's last two NGCC units, starting in 2032 and 2033, represent just over 31.26% of total portfolio capacity, but together account for 42.9% of stranded fixed costs that would be charged to ratepayers if the portfolio retired early at the end of 2050. Combined, these two facilities account for $2,072.26 million in unrecovered book value at the end of 2050 and $3,547.8 million of post-2050 fixed costs that would be charged to ratepayers if retired at the end of 2050.

[23] Stranded fixed costs are all fixed costs except for fixed O&M expenses.

Table 7 - Stranded Costs from Early Retirement of DEP Facilities ($ mill)

Facility Name	DEP CC-1 (2029)	DEP CC-2 (2030)
MW	1135	1360
Book Value, start year	$1,123	$1,721
Book Value, end of 2050	$417	$688
% of Starting Book Value, end of 2050	37.1%	40.0%
Total Fixed Cost Recovery after 2050	$639	$1,083
% Share of Portfolio Book Value in start year	9.6%	14.7%
% Share of Portfolio Book Value at end of 2050	8.3%	13.7%
% Share of Portfolio Total Fixed Cost Recovery after 2050	7.7%	13.1%

Table 8 - Stranded Costs from Early Retirement of DEC NGCC Facilities ($ mill)

Facility Name	DEC CC-1 (2031)	DEC CC-2 (2032)	DEC CC-3 (2033)
MW	1360	1360	1360
Book Value, start year	$2,132	$2,174	$2,220
Book Value, end of 2050	$914	$994	$1,078
% of Starting Book Value, end of 2050	42.9%	45.7%	48.6%
Total Fixed Cost Recovery after 2050	$1,504	$1,680	$1,868
% Share of Portfolio Book Value in start year	18.2%	18.5%	18.9%
% Share of Portfolio Book Value at end of 2050	18.2%	19.8%	21.4%
% Share of Portfolio Total Fixed Cost Recovery after 2050	18.2%	20.3%	22.6%

Table 9 - Stranded Costs from Early Retirement of DEC NGCT Facilities ($ mill)

Facility Name	DEC CT-1 (2029)	DEC CT-2 (2030)	DEC CT-3 (2031)
MW	850	850	425
Book Value, start year	$663	$1,125	$572
Book Value, end of 2050	$246	$450	$245
% of Starting Book Value, end of 2050	37.1%	40.0%	42.9%
Total Fixed Cost Recovery after 2050	$384	$721	$403
% Share of Portfolio Book Value in start year	5.7%	9.6%	4.9%
% Share of Portfolio Book Value at end of 2050	4.9%	8.9%	4.9%
% Share of Portfolio Total Fixed Cost Recovery after 2050	4.6%	8.7%	4.9%

Comparison of Fixed Cost Levelized Cost of Energy

The second component of our analysis of stranded costs resulting from early retirement of these plants at the end of 2050 examines the levelized cost of energy (LCOE) attributable to fixed- and investment-related costs. Unlike the first component of our stranded cost analysis, the amount of generation from these proposed natural gas facilities impacts the LCOE, so analysis of this component includes results from scenarios[24] with and without EPA's newly finalized regulations for new natural gas facilities taking effect.

Levelized Cost of Energy (LCOE)

The LCOE is a commonly used metric to compare the cost of energy among different resource options. However, the LCOE should not be confused with actual electric rates because electric rates are determined based on annual revenue requirements and the rate impact of any specific generating facility varies from year to year. Additionally, electric rate impacts as described elsewhere in our analysis are based on nominal values in future years, while the LCOE metric represents a single point of comparison based on the net present value[25] (NPV) of future-year values.

In simple terms, the LCOE is the NPV of future costs divided by the NPV of future output quantities, or generation. LCOE metrics typically include all costs over the lifetime of a generating facility, but for our purposes in examining the implications of stranded costs from an early retirement of Duke's proposed natural gas facilities we only include fixed- and investment-related costs. Additionally, our LCOE analysis considers fixed costs under a scenario where NGCC unit output is limited to a 40% capacity factor starting in 2032 by EPA's new GHG regulations and fixed costs under a scenario where NGCC output is not constrained by EPA's new GHG regulations and assumed at an 80% capacity factor. The fixed-cost LCOE of those operating scenarios is calculated based on each plant operating for its full 35-year life and then calculated based on an early retirement at the end of 2050.

Fixed Cost-LCOE Comparison with 35-year Operating Life

The first set of fixed cost-LCOE scenarios (i.e., Scenarios 1.A and 1.B) assumes that all of Duke's proposed plants operate for their full 35-year depreciable life and serves as a baseline against which we measure the impacts of an early retirement at the end of 2050 in the second set of fixed cost-LCOE scenarios.

The first of these 35-year operating life scenarios (i.e., Scenario 1.A) assumes that EPA's GHG regulations take effect as proposed and Duke's proposed NGCC units are limited to operating at a 40% capacity factor starting in 2032, while the second (i.e., Scenario 1.B) assumes Duke's proposed NGCC units operate at an 80% capacity factor throughout their depreciable life. Fixed costs in both of these scenarios have a combined NPV of about $24.22 billion, with nearly $18 billion attributable to DEC and $6.22 billion to DEP. The difference between these scenarios is total MWh sales resulting from capacity factor assumptions with and without EPA GHG regulations. As shown in Figure 17, when NGCC units are limited to a 40% capacity factor starting in 2032 by EPA GHG regulations the NPV of MWh sales quantities over a 35-year operating life is nearly 45% less than the scenario without EPA GHG regulations.

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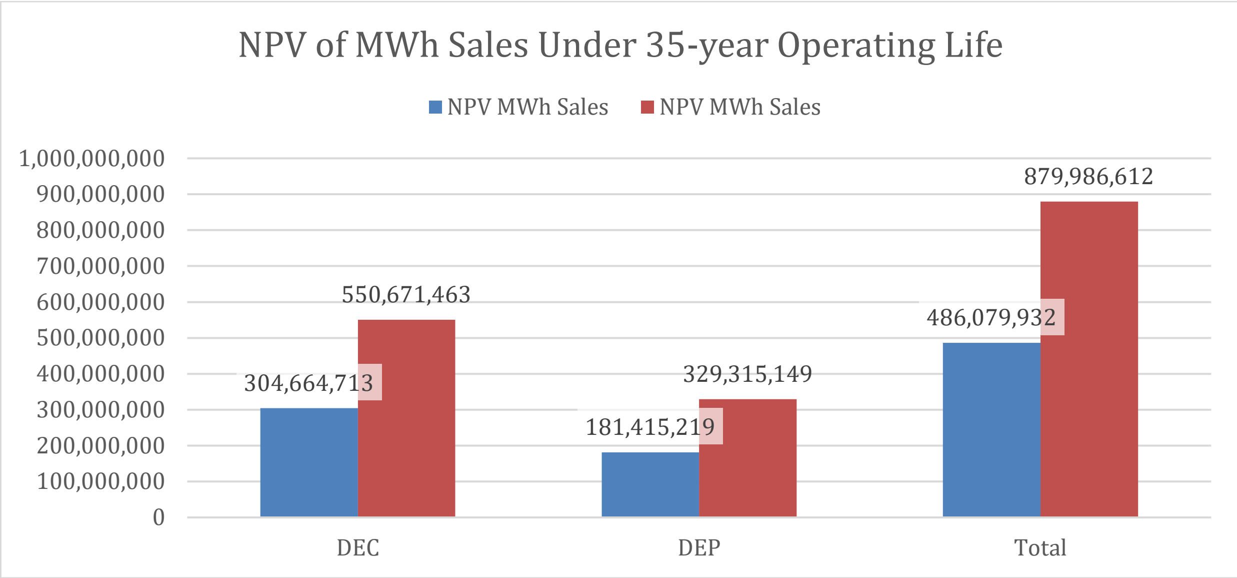
[24] With EPA's newly finalized rules NGCC units are restricted to operating at a 40% capacity factor in 2032 and beyond, and without EPA's newly finalized rules NGCC units are assumed to operate at an 80% capacity factor.
[25] All LCOE scenarios apply an assumed 2.5% inflation rate as the discount rate.

Figure 17 - NPV of MWh Sales with 35-year Operating Life

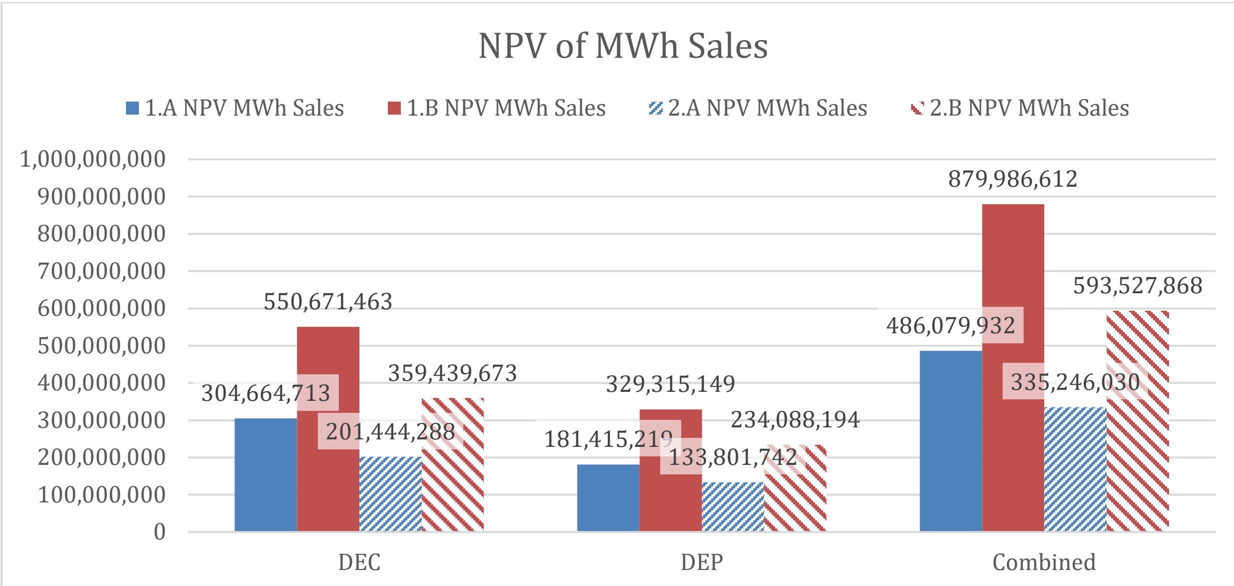


Because fixed costs do not vary between these scenarios, the lower MWh sales quantities result in a higher fixed cost-LCOE when Duke's proposed NGCC units' output is limited by EPA GHG regulations. For DEC the fixed cost-LCOE is 80.75% higher when emissions are limited by EPA regulations, while for DEP the fixed cost-LCOE is 81.5% higher with EPA GHG regulations in place, and the systemwide combined fixed cost-LCOE is 81% higher with EPA GHG emission regulations.

Fixed Cost-LCOE Comparison with Early Retirement

The second set of fixed cost-LCOE scenarios also compares results between Duke's proposed plants operating with and without EPA GHG regulations but does so under the assumption that all the proposed natural gas facilities retire at the end of 2050. Compared to the previous set of scenarios, early retirement reduces the NPV of fixed costs by about 12% for the combined systemwide portfolio (11.9% for DEC and 12.45% for DEP) because fixed O&M expenses are no longer incurred after the plants retire at the end of 2050. Also due to the early retirement, the NPV of MWh sales is also reduced, as shown in Figure 18.

Figure 18 - NPV of MWh Sales



The combination of these factors resulting from early retirement slightly reduces the difference between the fixed cost-LCOE as calculated with and without EPA GHG regulations. However, the more significant impact from early retirement (Scenarios 2.A and 2.B) is the increased fixed cost-LCOE for Duke's proposed natural gas plants resulting from the reduced lifetime output of the facilities.

For the full systemwide combined portfolio of Duke's proposed natural gas plants, early retirement at the end of 2050 increases the fixed cost-LCOE by 29.4% if the plants are operated in accordance with EPA's GHG regulations and increases the fixed cost-LCOE by 32.3% if operated at their estimated full output. For the DEP portfolio of proposed natural gas plants, early retirement at the end of 2050 increases the fixed cost-LCOE by 20.6% if the plants are operated in accordance with EPA's GHG regulations and increases the fixed cost-LCOE by 25.1% if operated at their estimated full output. For the DEC portfolio of proposed natural gas plants, which includes more units and later start dates than the DEP portfolio, early retirement at the end of 2050 increases the fixed cost-LCOE by 35.1% if the plants are operated in accordance with EPA's GHG regulations and increases the fixed cost-LCOE by 36.9% if operated at their estimated full output.

Stranded Cost Summary

The possibility of early retirement of these proposed plants clearly presents significant stranded cost risks. While it does not represent actual electric rates associated with these proposed plants, the fixed cost-LCOE serves as proxy metric demonstrating the additional costs ratepayers will incur over time if these plants are retired early at the end of 2050. Overall, early retirement increases the fixed cost-LCOE of Duke's proposed portfolio of new natural gas generation facilities by about 30%.

Section VI. Conclusions

Based on our analysis of Duke's proposed natural gas buildout in the 2023 NC CPIRP, we draw the following conclusions regarding Duke's proposal:

- Duke has offered no alternative proposals to the natural gas buildout, and so no comparative analysis of risks and impacts is possible, likewise no conclusions about the reasonableness or cost-effectiveness of Duke's proposal when compared to other resource mix possibilities are possible.
- Duke's proposal relied on low-GHG hydrogen co-firing as an option for compliance with the EPA's GHG regulations – an option which was removed from the EPA's final rule – with the result that Duke's proposed NGCC units will be limited to operating at a 40% capacity factor under EPA rules, which results in those units generating roughly half of the electricity each year that an NGCC unit is capable of generating, although ratepayers would still be required to pay the same amounts towards the fixed investment costs.
- Duke proposed natural gas buildout significantly increases costs to ratepayers, including residential ratepayers, and substantially increases ratepayer risks associated with high future natural gas prices, natural gas price volatility, and the potential for stranded costs.

Appendix A Additional Notes on Methodology

General Analytical Notes

What This Report IS and IS NOT

The addition of significant quantities of natural gas generation is a critical element of Duke's 2023 NC CPIRP, but the as-filed materials do not isolate the impacts of the natural gas generation component of the plan, nor do they fully present results under sensitivity and alternative or future scenarios (e.g., high natural gas prices, lack of future hydrogen availability). Given these gaps in available public information, the objective of this report is to provide greater transparency into the likely cost impacts and risks associated with Duke's natural gas resource build-out plans. It should not be read as a criticism of the sufficiency of Duke's resource planning modeling, the assumptions embodied within that modeling, the resulting resource portfolio that Duke recommends, or a recommendation for any specific alternative resource portfolio.

In other words, our analysis is not in itself a substitute for Duke's resource modeling and resource selection process, and it should not be interpreted as reaching a conclusion that Duke's recommended plan is "wrong" or more costly than any given alternative resource portfolio. Rather, it should be viewed only as a presentation of the potential risks and rate impacts of Duke's natural gas resource expansion plans that cannot be readily ascertained from the as-filed 2023 NC CPIRP documentation.

The Analysis is Based Exclusively on Public Data

Our analysis uses only data that is publicly available in the documents filed by Duke in the 2023 NC CPIRP (including its January 2024 Supplemental Filing), other North Carolina Utility Commission (NCUC) proceedings (e.g., annual fuel cost adjustment updates and monthly fuel cost reports), and third-party entities (e.g., certain cost estimates). The constraints associated with exclusive reliance on public information required the use of a variety of assumptions and workarounds to address circumstances where the as-filed information was insufficient for the analysis (e.g., lacking specificity, comprehensiveness, or simply not present), or was presented in a form that required interpretation to be usable (e.g., figures and graphs as opposed to data tables, only specified for select years rather than annually). These assumptions and workarounds included the use of historic data to develop critical inputs (e.g., generation unit capacity factors) and the extraction of specific data values from graphs.[26]

To be clear, our limitations in this regard should not be interpreted as a conclusion that Duke's provision of information and data to parties intervening in the 2023 NC CPIRP docket (E-100 Sub 190) is inadequate. Rather, they simply reflect the fact that not all data necessary for the analyses that we conducted could be obtained directly and completely from the documents publicly available in the NCUC's docket system.

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[26] Data extraction from graphs used the online Automeris.io WebPlotDigitizer V4 tool, available at: https://automeris.io/v4/. This tool was used to establish numerical amounts from graphs for: (a) annual natural gas price projections and (b) the annual percentage of system generation from natural gas generation.

Federal and State Carbon Emission Limitations Contain Uncertainties

Anticipated limitations on carbon emissions are core considerations with respect to resource selection, in particular as they pertain to the focus of this report on new natural gas generation resources. Our analyses are based on our reading and interpretation of the constraints imposed by current Federal and North Carolina law. Alternative interpretations and/or future legal developments could produce a different set of assumptions and results.

Natural Gas Price Analysis

General Methodology Description

The basic structure of this analysis centers on identifying an annual retail rate for natural gas costs that applies to sales of electricity to residential customers, which can then be multiplied by an assumed monthly level of usage to determine an average monthly bill impact by year. This retail rate, in turn, is calculated according to according to the following equation:

$$\frac{\text{System Revenue Requirement (\$)} * \text{NC Residential Class Allocation \%}}{\text{NC Residential Class Retail Sales (kWh)}}$$

The establishment of the inputs to this basic equation required the use of various datasets and assumptions as described further below.

System Revenue Requirement

The system revenue requirement was calculated as sum of revenue requirements for different types of natural gas generation units, differentiated as follows:

- Existing NGCC
- Existing NGCT
- Existing Dual Fuel Steam
- New NGCC
- New NGCT

For each unit type, a generation rate ($/kWh) was calculated based on an assumed heat rate (Btu/kWh) and annual delivered natural gas price ($/Btu), the latter amount of which was differentiated by utility due to meaningful differences in each operating utility's delivered natural gas price relative to base commodity prices. The generation rate was then multiplied by the expected amount of generation from each unit type during each year to produce the revenue requirement.

Natural Gas Prices

Forecasted Henry Hub gas prices were sourced from Figure C-4 in Duke's August 2023 NC CPIRP filing (Appendix C, p. 44). Specific annual prices were extracted from this graphic using an online data extraction tool (Automeris.io WebPlotDigitizer V4). In order to identify as-delivered natural gas prices inclusive of transportation, storage, and hedging costs, data on actually incurred natural gas prices from Duke's monthly fuel cost reports was used to establish an average percentage (%) premium of "all-in" delivered natural gas costs relative to monthly Henry Hub prices. The specific all-in prices used in our analysis incorporate a premium of roughly 30.4% for DEC and 56.2% for DEP based on the volume-weighted monthly average premium from 2017-2020. The 2017-2020 period was selected for this data point because it is indicative of a period of "normal" prices not affected by significant volatility and our analysis showed it to be fairly consistent (with a slight upward trend) over this time frame.

Heat Rates (By Unit Type)

Table A-1: Heat Rate Assumptions

Unit Type	Heat Rate (Btu/kWh)	Source Details
Existing NGCC	7,115	Avg. of DEC & DEP Monthly Median (2017-2023)
Existing NGCT	11,305	Avg. of DEC & DEP Monthly Median (2017-2023)
Existing Dual Fuel Steam	10,100	DEC Monthly Median (2022-2023)
New NGCC	6,490	2023 NC CPIRP Assumption
New NGCT	9,270	2023 NC CPIRP Assumption
Overage Adjustment*	8,500	General Assumption

* The Overage Adjustment was used to align amounts of natural gas generation from our projections based on our general unit type capacity factor assumptions with Duke's natural gas generation projections, as discussed further below. It represents dispatch of existing gas generation above historic amounts needed to meet Duke's forecasted amounts of natural gas generation.

Annual Generation By Unit Type

Initially, generation by unit type was calculated based on annual unit capacities presented in Duke's 2023 NC CPIRP and assumed capacity factors. The assumed capacity factors shown below were selected based on Duke's projected amounts of natural gas generation by year, historic capacity factors of existing natural gas generation units, and emission limit constraints on new natural gas generation.

Table A-2: Gas Generation Assumptions

Unit Type	Capacity Factor (%)	Source Details
Existing NGCC	80%	5-Year historic average of highest performing units + premium to reflect added energy needs
New NGCC	80% (40%)	80% through 2031 based on premium above historic average of highest performing units due to added energy needs; 40% in 2032 and thereafter
Existing and New NGCT	15%	5-Year historic average of highest performing units + premium to reflect added energy needs
Existing Dual Fuel Steam	N/A	Generation assumed based on 2022-2023 unit averages; adjusted for planned unit retirements

These assumptions were initially used to produce annual natural gas generation amounts that were then compared to Duke's projected amounts in its January 2024 Supplement.[27] The base estimated generation amounts by unit type were then adjusted so that annual gas generation amounts align with Duke's projections. Downward adjustments, where necessary, were accomplished first by reducing generation from existing dual fuel steam units, and then existing NGCC units. This reflects an assumption that NGCTs could not be ramped down because their generation is necessary during peak periods, and the dual fuel units would be the least dispatched units due to their lower generating efficiency. For years requiring upward adjustments, an "overage" amount was calculated based on a generalized heat rate of 8,500 Btu/kWh, effectively reflecting a blend of different unit types. Utility-specific amounts were assigned to each operating utility based on their annual share of total system energy needs.

NC Residential Allocators and Sales

The residential class allocation used an annual projection based on forecasted North Carolina residential energy needs at the generator compared to total system needs. Annual residential retail sales amounts by operating utility were sourced from Tables D-19 (DEC) and D-20 (DEP) of Duke's August 2023 filing.[28] The North Carolina portions of residential sales for each utility were calculated based on a 3-year average (2021-2023) percentage of North Carolina residential sales compared to total North Carolina and South Carolina residential retail sales using data from U.S. Energy Information Agency Form 861 and 861M.

The resulting retail amounts were grossed up to sales at the generator using each utility's average line loss factor. The annual North Carolina energy allocators were then calculated by dividing projected North Carolina residential sales at the generator by forecasted total utility sales at the generator for each operating utility. The forecasted North Carolina residential retail sales amounts described above were used to translate annual costs to a retail natural gas rate.

Volatility Analysis

The volatility analysis is based on mimicking the shape of the natural gas price volatility that occurred from September 2021 to December 2022 and applying it to Duke's projected base natural gas price forecast amounts. To do this, volatility premiums were established for each month from September 2021 to August 2023 based on each operating utility's actual NGCC gas prices sourced from monthly fuel reports, and their projected natural gas prices from annual fuel cost adjustment proceedings.

Revenue Requirement Calculation

General Methodology Description

The revenue requirement for each individual generating unit was modeled based on the generating unit's planned start year in the NC CPIRP, operating utility owner (i.e., DEP or

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[27] Annual gas generation percentages were extracted from Figure SPA 3-1 of the January 2024 Supplement and applied to projected system needs sourced from Tables SPA 2-8 (DEC) and SPA 2-9 (DEP) from the January 2024 Supplement.
[28] Duke did not present class-level projected sales in the January 2024 Supplement.

DEC), whether Duke has indicated transmission costs are included for that unit, the unit nameplate capacity in megawatts (MW), the type of unit (i.e., NGCC or NGCT), and a selected cost scenario for capital investment, fixed O&M, variable O&M, and associated heat rates. Additional inputs include a gross-net adjustment factor specific to each operating utility to account for line losses and auxiliary loads and estimate electricity quantity available at customer meters and the ability to adjust each unit's assumed capacity factor in each year of operation. The revenue requirement model output represents monetary values in each year in nominal dollars.

The revenue requirement for a generating unit in each year is based on straight-line depreciation, as required for ratemaking purposes, over a 35-year estimated life and does not include any tax-normalization adjustments. The return on equity (ROE) in a given year is the percent equity for the operating utility's capital structure multiplied by the operating utility's current ROE multiplied by the mid-year book value of the generating unit (to approximate average annual return). The interest expense in a given year is the percent debt for the operating utility's capital structure multiplied by the operating utility's cost of debt multiplied by the mid-year book value of the generating unit (to approximate average annual interest expense).

The pre-tax revenue requirement is calculated as the sum of annual depreciation expense, the return on equity, interest expense, and fixed O&M expense. Tax expense is then determined as the operating utility's assumed effective tax rate multiplied by the pre-tax revenue requirement less the sum of interest, depreciation, and fixed O&M expenses, or, in simpler terms, the effective tax rate multiplied by the return earned on equity. The capital and fixed cost portion of the generating unit's annual revenue requirement is the sum of the pre-tax revenue requirement and the tax expense.

The revenue requirement model then determines operating expenses – including variable O&M and fuel costs based on projected gross generation. Because variable O&M expense estimates are not provided in the NC CPIRP, the model uses variable O&M expenses from the National Renewable Energy Laboratory 2023 Advanced Technology Baseline (NREL 2023 ATB) for advanced natural gas turbines. Fuel consumption quantity is determined based on the estimated heat rates for NGCT and NGCC units in the NC CPIRP, and fuel expense is estimated as the product of fuel quantity in each year and estimated average annual fuel price scenarios. All operating expenses are calculated based on gross generation.

The after-tax revenue requirement attributable to the fixed and capital cost component is added to the revenue requirement attributable to the operating expense component to generate the total annual revenue requirement for each unit in each future year. Generating unit-level annual revenue requirements are summed for each operating utility to provide the total annual revenue requirement for each utility's proposed portfolio.

Utility-Specific Capital Assumptions

Key capital-specific assumptions used in the revenue requirement model for each operating utility are shown in the table below. For each utility, the current approved ROE, cost of debt, and capital structure was applied in all years. An effective income tax rate of 21% was assumed in all years based on the permanent corporate federal income tax rate of 21% established in the 2017 tax reform act (Public Law No. 115-97)[29] and the phase-out of the North Carolina state corporate income tax by 2030.[30]

Table A-3: Capital Cost Assumptions

Assumption	DEC	DEP
ROE	10.10%	9.80%
Interest (i.e., Cost of Debt)	4.56%	4.03%
Debt %	47.00%	47.00%
Equity %	53.00%	53.00%
WACC %	7.50%	7.09%
Effective Tax Rate	21.00%	21.00%

Generating Unit Cost Factors

This analysis relies on estimates from the NC CPIRP to the extent possible. The baseline scenario results use the NC CPIRP's mid-level estimates for generating-unit capital cost, and utility- or generator-type estimates for heat rates, depreciable life, and transmission upgrade costs for applicable units. As previously noted, the NC CPIRP does not include O&M expense estimates, and the analysis uses O&M expense estimates from NREL's 2023 ATB for advanced non-carbon capture units. A utility-specific factor is applied to adjust gross generation for losses and estimate the portion of gross generation that is ultimately metered for retail sale.

Generating unit capital costs from the NC CPIRP are converted to 2024$ based on the historical 2.5% inflation rate used in NREL's 2023 ATB, and then adjusted based on each generating unit's planned start year using learning curve ratios from the NC CPIRP, plus inflation, assuming the capital cost from the year prior to the operating start year. Where identified in the NC CPIRP as applicable, a transmission cost upgrade is added to the unit capital cost of $450,000/MW in DEC territory and $220,000/MW in DEP territory, in 2023$ and adjusted for annual inflation of 2.5%. All generating units are assumed to have a depreciable life of 35 years.

Residential Class Allocation and Rate Derivations

The residential rate derivations for this portion of the analysis were generally calculated in the same manner as those associated with the natural gas price analysis by assigning the utilities' respective residential classes a portion of the total revenue requirement and then calculating the equivalent retail rate by dividing that amount by projected retail sales during a given year. The North Carolina residential allocators for fixed costs were set at a uniform amount during all years of 18.82% for DEC and 33.32% for DEP. These amounts are based on the allocators for production demand contained in DEC's most recent cost of service study (COSS) reflecting a 2021 test year filed as part of its most recent rate case (Docket No. E-7 Sub 1276) and DEP's

[29] *See* https://taxsummaries.pwc.com/united-states/corporate/significant-developments
[30] *See* https://poole.ncsu.edu/thought-leadership/article/north-carolina-set-to-become-the-newest-0-corporate-income-tax-rate-state/

April 30, 2024 COSS update filing with the NCUC reflecting a 2023 test year (Docket No. E-2 Sub 1300). The specific percentages refer to the residential class allocation of total system-wide production demand inclusive of wholesale loads and South Carolina retail loads, which would also be allocated a portion of new fixed costs.

Our use of a uniform allocation across all years is reflective of the data limitations associated with using only publicly available data. The as-filed 2023 NC CPIRP materials do not contain class-level demand projections in either the initial August 2023 filing or the January 2024 Supplement filing. In addition, the as-filed COSS materials do not contain the specific calculations associated with the 12-Month Coincident Peak Average and Excess method (12CP A&E) that Duke now uses for fixed production demand costs. Collectively, and even individually, both instances of data unavailability preclude us from establishing reliable forward projections of class-level fixed cost allocation.