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February 2021

Institute for Energy Economics and Financial Analysis
IEEFA.org

Key Shortcomings in Duke's North Carolina IRPs

An Issue-by-Issue Analysis: Part 2

Executive Summary

Duke Energy's proposed integrated resource plans (IRPs) for its two operating North Carolina utilities—Duke Energy Carolinas and Duke Energy Progress—outline six possible scenarios for the company to follow in the next 15 years.

Five scenarios entail significant new gas-fired power generation capacity to meet forecasted future power needs across its service territory. A sixth 'no new gas' scenario carries the highest estimated cost—almost as if Duke set it up as a strawman designed to illustrate that turning away from gas would be bad policy. Instead, it shows that the transition can indeed be accomplished without new gas generation, and the question now is just how to go about it to keep costs as low as possible.

In this series, IEEFA examines specific aspects of the Duke proposals to highlight errors we believe policymakers in the state need to consider. Among these are a review of Duke's assumptions concerning natural gas—both for new gas supply and gas-fired generation resources—which we believe are directly at odds with the company's 2050 net-zero carbon pledge; its assumptions regarding battery storage; and a look at its approach toward new solar and wind generation capacity.

The analysis below focuses on Duke's demand growth assumptions, which we believe are overstated and will be used to justify the need for new generation resources, particularly gas capacity.

Duke's Overstated Demand Growth Forecasts

It's Time to Study No-Growth Scenarios

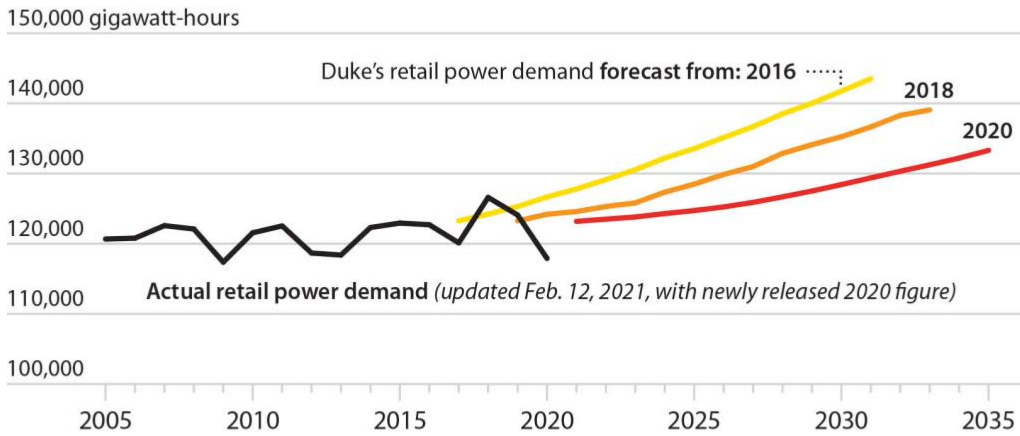
Most U.S. utilities consistently overestimate future demand growth, and Duke is no exception. Unfortunately, these overstated forecasts skew the conversation with regulators, since utility executives use steadily rising outlooks to push for approval of new generation resources, regardless of whether they are truly needed.

The latest integrated resource plans from Duke's two Carolina utilities—Duke Energy Progress and Duke Energy Carolinas—clearly highlight this problem. The two utilities still file separate resource plans with state regulators, despite merging under the Duke Energy umbrella in 2012, and they share the same forecasting approach to electricity sales—predict growth and hope for the best.

A close look at Duke's recent forecasts shows just how misleading these projections can be. Duke's just-released retail sales figures for 2020 totaled 117,970 gigawatt-hours (GWh), pushing sales down to their lowest level since 2009. In essence, the utilities' sales have been flat since 2005, staying close to the 120,000 GWh level. Despite this, as the three forecast lines on the right of the figure below illustrate, the companies have continued to project demand growth in their recent IRPs.

Duke Forecasts Rising Retail Power Demand, But History Shows No Growth

In its last three retail power demand forecasts—in 2016, 2018, and 2020—Duke Energy has kept its starting point the same, at about 123,200 gigawatt-hours, reflecting a continuation of little growth for the past decade. Duke has also sharply cut back on the growth it expects over the next 15 years.



Source: Duke Energy Integrated Resource Plans IEEFA

IEEFA analyzed the company's estimates for residential demand growth in greater depth because they are the largest single segment of Duke's retail sales, accounting for 37.6% of the total across both units from 2010-2019, and the area where Duke consistently expects the highest growth.

- DEC forecasts residential sales will rise by an annual average of 1.0% from 2021-2035, accounting for 73.5% of the growth projected for the unit's total retail sales during the period.

- DEP projects its residential sales will rise by an annual average of 1.4% during this same period, accounting for essentially all the growth in the unit's retail sales.

Duke has made similarly optimistic projections about residential sales growth in prior IRPs, as Table 1 illustrates.

Table 1: Projected Residential Sales Growth (Annual Average Through 15-Year Forecast Period)

	2014	2016	2018	2020
DEC	1.1%	1.2%	1.3%	1.0%
DEP	1.3%	1.1%	1.1%	1.4%

Source: Duke Energy IRPs.

But residential sales are not growing. Between 2010 and 2019, the units' residential sales fell slightly. In 2010, total residential sales were 47,166 GWh; in 2019 they totalled 47,038 GWh—essentially zero growth, and nowhere close to the projected average annual growth rates of 1% or more.

Despite this evidence—and while acknowledging that energy efficiency and demand reduction programs will continue to push per-capita energy usage down—both Duke units still expect increases in electricity demand in the next 15 years, based on continued population growth across their service territories. Together, the two units project that the total number of residential customers will climb by 786,000 in the next 15 years (roughly 1.4% annually), pushing up total residential sales by 8,515 GWh annually.

This expectation also runs counter to Duke's own experience. The number of residential customers served by DEC and DEP rose by 360,000 from 2010-2019, an annual average increase of just over 1.1%—but total residential sales did not grow at all.

Duke is the in same situation as utilities across the country: Energy efficiency measures, growing amounts of behind-the-meter rooftop solar and a transition away from energy-intensive industries have resulted in flat electricity demand across the U.S. since 2010, despite continued population and economic growth. Total electricity sales in the U.S. climbed just 0.15% annually from 2010-2019, while the population rose from 309 million to 328 million and gross domestic product increased at an average annual rate of 2.24%.

While Duke's projected annual increases are small, they add up over time.

While Duke's projected annual increases are small, they add up over time. For example, DEC is projecting in its base-case resource forecast that its annual residential sales will rise by an estimated 4,462 GWh by 2035—and is telling regulators that it needs to build another combined cycle (CC) gas plant to meet that need. For illustrative purposes, a 675-megawatt (MW) combined cycle gas plant running at a capacity factor of about 75% would generate roughly that amount of electricity annually.

The same slow-but-steady growth projection in DEP's pending IRP would boost residential sales by 4,053 GWh by 2035, which could be used by the utility to justify a new combined cycle gas plant, or even two, depending on their size. DEP's newest power plant, the 560MW CC facility at Asheville that came online earlier this year, will generate roughly 3,700 GWh annually if it operates at a 75% capacity factor.

Any new gas plants would be expensive additions to Duke's generation fleet—the Asheville facility alone cost $817 million. Costs to ratepayers could rise even higher if those new plants are forced to retire before the end of their operating lives, as is likely (See Part 1 for a more detailed discussion of this issue).

Adding the smaller amounts of growth expected in the commercial and industrial sectors pushes Duke's projected combined growth to more than 10,000 GWh by the end of the forecast period. This projected commercial and industrial increase in power use would likely be used by the utilities to bolster their push for new gas generation units—but like past projections of residential demand growth, could also turn out to be just a mirage.

A similar disconnect can be seen in Duke's forecasts for peak demand growth, which also have consistently overstated actual results. In 2014, DEC projected that summer peak demand (after accounting for energy efficiency programs) would climb from 18,486 MW in 2015 to 20,291 MW in 2021—a level that DEC's latest IRP does not see the company reaching even by 2035, the end of the current forecast period. DEP's forecasts have been similarly off the mark. In 2014, it projected summer peak would climb to 14,007 MW in 2021; the unit now doesn't expect to hit that level until 2033.

Even though both Duke units have lowered their peak demand forecasts in their latest IRPs, they still expect growth. As justification, both units again turn to their expectations that rising population will drive growth. DEC, for example, writes: "Over the 15-year planning horizon, the company projects the addition of 560,000 new customers in DEC contributing to 1,650 MW of additional winter peak demand on the system."

The companies' actual results undercut this forecast.

Again, the companies' actual results undercut this forecast. From 2014-2019, the number of retail customers served by DEC rose by 199,000 or about 8.1%. But peak demand did not follow. In 2014, DEC's peak demand in the winter hit 18,275 MW; in both 2019 and 2020, the winter peak was below 17,000 MW despite customer growth during the period. Even using DEC's weather-normalized figures, the winter peak was higher in 2014 than 2020. Similar results can be seen at DEP, where the number of retail customers rose 105,000 (about 7.0%) from 2014-2019 while peak demand remained essentially unchanged.

Separating Economic Growth From Load Growth

There are numerous examples in the U.S. of successful efforts to curb peak load growth and flatten or reduce net load on utility systems. Here, efforts by ISO-New England stand out: A combination of energy efficiency, demand side management and strong, behind-the-meter growth in rooftop solar has helped hold peak demand at roughly 25,000MW since the early 2000s and cut net energy for load by more than 10%. The grid operator expects these trends to continue, writing in its 2020 outlook that energy efficiency and behind-the-meter solar will reduce peak demand growth and overall grid electricity use over the next 10 years.[1]

On top of this, the significant recent rise in battery storage deployments offers utilities a series of options for cutting peak demand growth. This issue will be addressed in a separate analysis.

The new gas plant proposals in both Duke IRPs are predicated on the company's estimates of future demand and peak load growth. If those forecasts prove overstated, as the company's past forecasts have been, then ratepayers could end up with the bill for expensive and unneeded new capacity—capacity that also will have to be retired years before the end of its economic lifespan to comply with Duke's 2050 net-zero carbon emissions goal. North Carolina regulators should require both Duke operating units to address these issues by conducting additional forecasts—ones that hold electricity demand growth and peak demand growth flat in the coming 10 to 15 years—and submit those results as part of the ongoing IRP process.

[1] ISO New England. 2020 Regional Electricity Outlook. February 2020.

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The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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