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Natural gas use in electricity generation in the United States: Outlooks to 2030☆

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ABSTRACT

The authors investigate uncertainties that could affect the usage of natural gas for electricity generation in the United States, including the pace of installing renewable generation resources, natural gas prices, and retirement of nuclear plants. The long-term modeling suggests natural gas usage for power generation in year 2030 could range from 8.7 to 15.1 trillion cubic feet, with the price of natural gas appearing to be the most important factor.

1. Introduction

The U.S. electricity industry is going through yet another significant transformation, with increasing penetration of wind and solar generation, sustained low prices of natural gas, stagnant load growth possibly driven by increased demand-side resources and energy efficiency, and new environmental regulations, among other factors. These changes have already led to record levels of natural gas-fired electricity generation.[1]

Cheap natural gas and subsidized renewable generation resources with low operating costs have been keeping wholesale prices low, which in turn challenges the economic viability of many existing plants. Owners of coal plants find it difficult to justify investment in new equipment to comply with new and anticipated environmental regulations. More than 47 gigawatts (GW) of coal capacity was retired between 2010 and 2015 (with another 14 GW expected to retire between 2016 and 2018).[2] Reduced revenues have challenged nuclear plants as well: 4.4 GW of nuclear capacity was retired prematurely by the end of 2015. Plant owners have also announced another 5 GW of premature retirements, with additional 5–6 GW of nuclear capacity at risk.

These retirement prospects raise future reliability concerns throughout the country, especially in areas with competitive wholesale electricity markets. Reforms of capacity markets and improvements in real-time price formation adjustments may help improve price signals but they may not be sufficient. It appears that many electricity grids will increase their reliance on natural gas to replace retired baseload capacity and to balance the intermittence of renewable generation. However, many states are trying to save some coal and nuclear units via out-of-market support mechanisms. Also, the long-term availability and price of natural gas, as well as the harmonization of natural gas and electricity systems, require continued attention in this ever-changing market. Timely and efficient investments along the natural gas supply chain will depend largely on clarity around the future path of gas-fired power generation.

In this article, we investigate key parameters that could affect natural gas use in power generation through 2030, including the pace of renewable generation growth; natural gas price outlooks; and potential premature retirement of some nuclear plants. We utilize a power market model to conduct long-term resource expansion simulations under six different scenarios by combining different assumptions on the key parameters.

Our results suggest that the share of gas-fired generation nationwide could range from 27% to 47% in 2030, which implies a 6.4 trillion cubic feet (tcf) range (roughly from 8.7 tcf to 15.1 tcf) in terms of natural gas usage, or about 23% of total natural gas consumption in the U.S. in 2015. The 2016 *Annual Energy Outlook* (AEO) by the U.S. Energy Information Administration (EIA), when assuming no implementation of the Clean Power Plan (CPP),

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[1] Natural gas-fired generation has surpassed coal generation on a monthly basis since April 2015 and is expected to reach record level in 2016. See U.S. Energy Information Administration (EIA), *TODAY IN ENERGY*, July 14, 2016. "Natural gas-fired electricity generation expected to reach record level in 2016." Accessed on Sept. 15, 2016 at http://www.eia.gov/todayinenergy/detail.cfm?id=27072.

[2] Data source: SNL Energy *Regional Coal Unit Retirement Summary*.

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forecasts 9.7 tcf of gas usage in the electricity sector in 2030, which constitutes 31% of total generation, close to the bottom of our range.[3]

Among all key input assumptions, our modeling results suggest that natural gas price is the dominant factor influencing the outlook of gas-fired power generation: 12–13 tcf of gas may be needed in 2030 with low natural gas prices, but high prices would reduce the gas burn to about 9 tcf, lower than the 2015 and 2016 levels. Higher natural gas prices would increase not only wind and solar penetration but also increase coal generation and average revenue ($/MWh) for the gas fleet, despite lower generation from natural gas plants.

In Section 2, we discuss the model and key input assumptions for long-term resource expansion scenarios. We present our modeling results in Section 3, and offer some concluding remarks in Section 4.

2. Model assumptions and scenarios

2.1. Model description

We utilize AURORAxmp, a commercial economic dispatch tool, to model long-term (LT) resource expansion in the U.S. power market (including the Eastern Interconnection, Western Interconnection, and ERCOT).[4] The model retires existing resources and builds new resources based on annualized resource value of the asset, following an iterative optimization algorithm. In each LT iteration, the model places an updated set of retirement and new resource candidates in the system and performs the standard chronological commitment and dispatch. The model then tracks the resource costs and value of all new and existing resources based on the market prices developed in the iteration, and determines the mix of resources in the system that are most profitable while adhering to all constraints or that minimizes the total system cost.[5] Our study horizon covers 15 years from 2016 through 2030. However, we expanded the simulation to 2040 in order to have better model convergence in later years of our study period (e.g., 2025 to 2030). Doing so, we can assure that the model builds or retires a resource in later years of our study period based on at least a 10-year economic evaluation.

2.2. Key assumptions

We constructed scenarios to forecast the range of uncertainty around long-term outlook of gas-fired generation based upon three key factors: the installed capacity of wind and solar, natural gas price forecasts, and nuclear capacity retirement.[6]

2.2.1. Wind and solar capacity expansion

Fueled by federal tax credits, state renewable portfolio standards (RPS) programs, other state or local programs or policies, and declining overnight capital costs, renewable energy resources have been penetrating the generation mix at an unprecedented rate in recent years. Installed capacities of wind turbines and utility-scale solar PV installations reached 73 GW and 13.5 GW respectively at the end of 2015.[7] Renewables are reshaping the electricity market while creating new challenges to the power system. For example, it is common to observe negative wholesale electricity prices during periods of substantial wind generation and low load,[8] or the “duck curve” associated with intermittent solar power.[9] Renewables have low operating costs. When marginal, they can lower the nodal market-clearing price below the levels set by cheap natural gas and further undermine the revenues for conventional thermal units. This “missing money” problem raises concerns regarding early retirements and/or the lack of new capacity coming online in a timely manner.[10]

Over the years, we found that the model does not build wind and solar resources as much as what actually is constructed.[11] Although we capture federal tax credits in the cost structure of wind and solar as model inputs, these credits have not been sufficient to overcome the higher capital cost of wind and solar (relative to gas-fired plants) for model's economics algorithm to prioritize them for new builds over gas-fired generation. We observe that projects also benefit from revenue streams other than energy or capacity prices from the electricity markets. However, the paucity of data prevents us from credibly predicting the future likelihood or magnitudes of local benefits (e.g., tax exemptions), revenues from the sale of renewable energy credits (RECs), terms of long-term power-purchase agreements (PPAs) offered by some utilities and cooperatives, or any other programs.

Some state RPS programs rely on REC markets; many utilities or cooperatives sign PPAs driven by the RPS mandates. However, in this analysis, we prefer not to mandate RPS targets because states have not always met their targets fully on time; and some states such as Texas have surpassed their RPS targets quickly and

[3] The 2016 AEO reference scenario assumes the implementation of the CPP. With this scenario, gas-fired plants account for 37% of total electricity generation in 2030, the middle of our range. We did not model CPP explicitly but we also obtain 37% from a run with default CO_2 prices (starting in 2022 and increasing) in the model that are assumed to approximate the CPP assuming a national, mass-based compliance strategy.

[4] A detailed description of model capabilities is available at http://epis.com/aurora_xmp/power_forecasting.php.

[5] We use the mixed-integer programming (MIP) algorithm. AURORAxmp provides two optimization options: to maximize the value of the resources (i.e., a mix of resources that are most profitable), or to minimize total system cost. We employed the option to maximize value for the ERCOT runs because it provides better stability in energy-only markets, and the option to minimize cost for the Eastern Interconnect and the Western Interconnect runs.

[6] We also evaluated a low-load-growth scenario, using alternative load forecasts from ISOs and RTOs. The results were not significantly different probably because the difference in total load between the reference and low-load-growth scenarios was only 1.5% nationwide in 2030. We did not report these results in this article, but they are available upon request.

[7] U.S. EIA Form 860, *Annual Electric Generator Report*. Early Release 2015 data. Retrieved August 23, 2016 at https://www.eia.gov/electricity/data/eia860/.

[8] Bloomberg, April 5, 2016. “One Thing California, Texas Have in Common Is Negative Power.” Accessed on Sept. 28, 2016 at http://www.bloomberg.com/news/articles/2016-04-05/one-thing-california-texas-have-in-common-is-negative-power.

[9] Bloomberg, October 20, 2015. “The California ‘Duck Curve’ That Will Jolt Its Power Grid.” Accessed on Sept. 28, 2016 at http://www.bloomberg.com/news/articles/2015-10-21/california-s-duck-curve-is-about-to-jolt-the-electricity-grid.

[10] In this environment, companies and regulators are exploring out-of-market solutions such as long-term power purchase agreements (PPAs). For example, Ohio regulators approved PPAs with a couple of companies but FERC blocked this agreement (Accessed on Sept. 28, 2016 at http://www.utilitydive.com/news/ferc-blocks-ohio-power-plant-subsidies-for-aep-and-firstenergy/418297/). Later, Ohio regulators approved a “distribution modernization rider” to one of the companies (Accessed on Oct. 21, 2016 at http://www.utilitydive.com/news/re-regulation-vertically-integrated-utility/428639/). Another example was Maryland's contract with a company to build a new gas-fired plant, which the Supreme Court overturned (Accessed on Sept. 28, 2016 at http://www.utilitydive.com/news/what-the-hughes-v-talen-supreme-court-decision-means-for-state-power-incen/418046/). New York Clean Energy Standard provides another regulatory attempt to save nuclear plants that would have otherwise retired (Accessed Dec. 26, 2016 at https://www.governor.ny.gov/news/governor-cuomo-announces-establishment-clean-energy-standard-mandates-50-percent-renewables). Finally, Illinois passed an energy bill that provides annual support for Exelon nuclear plants (Accessed Dec. 26, 2016 at http://www.utilitydive.com/news/illinois-passes-sweeping-energy-bill-with-support-for-exelon-nuclear-plants/431521/).

[11] For example, see Gürcan and Soni (2013), and Gülen and Bellman (2015).