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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).

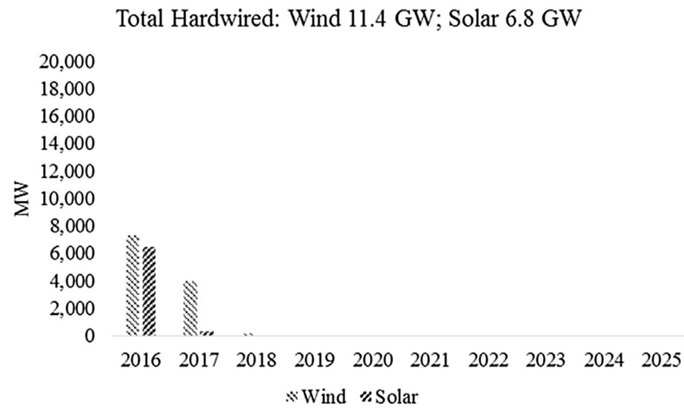

Fig. 1. Hardwired Wind and Solar Capacity in the Current Trends Scenario.

significantly.[12] The future energy policies and technology cost trends, especially for solar, storage, and demand-side resources carry a large range of uncertainty.[13]

We prefer to capture most recent cost predictions as model inputs and evaluate model's economic decisions to build and retire. As discussed later, predicted cost reductions for wind and, especially, solar PV are significant, which leads the model to build large amounts of wind and solar, but most of this build-out takes place after 2025 and fails to capture current projects. Accordingly, we "hardwire" renewable capacities that were under construction or in various stages of planning and development as of July 2016 as model inputs.[14]

We first establish a "Current Trends" scenario for renewable capacity expansion, by hard-wiring 11.4 GW of wind and 6.8 GW of solar PV capacity that were under construction as of July 2016. The majority of these projects will come online by 2018 (Fig. 1).

We also construct an "Aggressive Renewables" scenario, by additionally hardwiring 45.9 GW of wind and 13.1 GW of solar capacity that were not under construction but were in various stages of development or recently announced as of July 2016 (Fig. 2). We realize that additional projects in early development or recently announced are not likely to be developed at the pace depicted in Fig. 2. This scenario has become more realistic, at least in terms of capacity, with the extension of the federal tax credits at the end of 2015, which is likely to induce more expansion in the near future.[15] The Renewable Energy Buyers Alliance and similar initiatives are also supportive of a scenario of faster renewable expansion.

2.2.2. Natural gas price sensitivity

To capture the uncertainty of future gas prices, we employ two forecasts of the Henry Hub (HH) price up to 2040.[16] The Reference scenario is the average annual HH price forecast from Hahn et al. (2016). The second forecast is the reference case forecast from the *Annual Energy Outlook 2016* by the EIA. We added monthly variation to forecasted annual prices based on historical patterns (Fig. 3).[17]

2.2.3. Nuclear capacity retirements

Suppressed electricity prices in recent years significantly challenged the economic viability of the existing U.S. nuclear fleet, particularly those operating in competitive wholesale markets. Five reactors (over 4 GW) have been retired prematurely between 2013 and 2015, and more nuclear capacity are at risk of early retirement because of continued economic pressure or state policy.[18] Although state efforts such as the new energy bill in Illinois and New York's new clean energy standard program will likely save some of these plants, market and policy uncertainties remain even in these states. Hence, we cannot overlook the possibility of further premature nuclear retirements around the country.

The model does not retire nuclear units that either retired recently or are set to retire in the near future. This may be the result of the fixed and variable operating and maintenance costs (FOM and VOM) assumptions in the model being different from those realized by operators of these nuclear plants. For instance, Nuclear Energy Institute reports great heterogeneity on capital and

[12] The Brattle Group also pointed out that the RTO/ISO markets played a critical role in facilitating renewable generation development. (Accessed Dec. 25, 2016 at http://www.brattle.com/system/publications/pdfs/000/005/379/original/The_Role_of_RTO_ISO_Markets_in_Facilitating_Renewable_Generation_Development.pdf?1481213142).

[13] For example, the quality of wind and solar are location-dependent (wind speed and insolation); most current projects are being developed in best locations. The viability of remaining locations should decline over time unless there is equivalent improvement in cost and technology.

[14] We cross-referenced different data sources, including generator interconnection reports from various ISOs and RTOs, and the SNL Power Projects database.

[15] Bloomberg New Energy Finance predicts the tax credit extensions to fuel $73 billion increase in investment leading to additional 19 GW of wind and 18 GW of solar between 2016 and 2021 (Accessed on Sept. 28, 2016 at http://www.bloomberg.com/news/articles/2015-12-17/what-just-happened-to-solar-and-wind-is-a-really-big-deal).

[16] Note that we also incorporate forecasts of basis differentials between the Henry Hub and other key hubs around the country so that generation economics in different parts of the country is evaluated as appropriately as possible. Differentials are calculated by authors based on data from SNL.

[17] One would expect the changes in gas burn in the power sector to influence natural gas prices, at least in certain regions at certain seasons, which in turn could influence gas burn levels. In the future, we plan to integrate AURORAxmp with a detailed North American natural gas model to capture the interaction between gas demand for power generation and natural gas prices. For now, the two distinct price scenarios allow us to cover a reasonable range of outcomes.

[18] For instance, in June 2016 Exelon announced early retirement of its Clinton and Quad Cities plants by 2017 and 2018 due to market factors (See http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement). PG&E announced its plan to close Diablo Canyon by 2025 per state policy in favor of renewable resources (See https://www.pge.com/includes/docs/pdfs/safety/dcpp/diablo-canyon-retirement-joint-proposal-application-prepared-testimony.pdf). The new energy bill in Illinois (endnote 10) will likely save Clinton and Quad Cities plants.

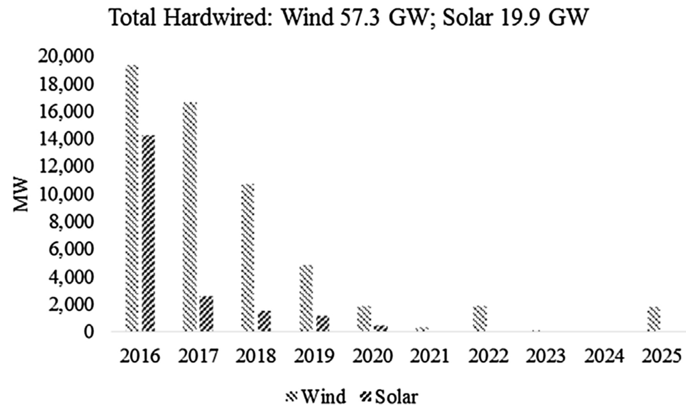

Fig. 2. Hardwired Wind and Solar Capacity in the Aggressive Renewables Scenario.

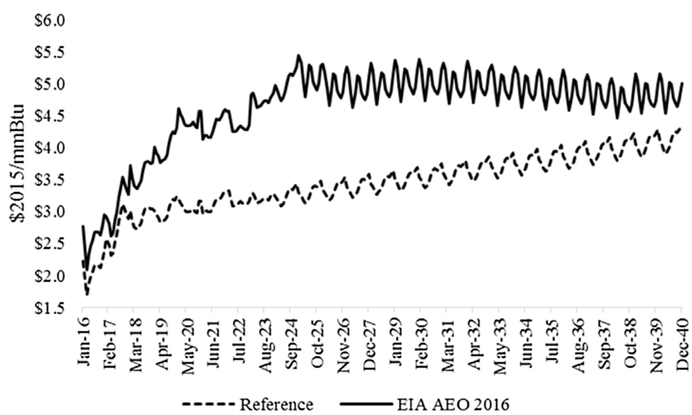

Fig. 3. Henry Hub Natural Gas Price Forecasts.

operating costs across different plants and fleet size.[19] However, we do not have these plant-specific proprietary cost data. We also realize that companies' decision to retire some nuclear units is a function of their overall generation fleets and regions of operations. We are not privy to how these factors contribute to company finances and strategies.

Hence, we consider a scenario where 43 GW of nuclear capacity operating in wholesale markets within the Eastern Interconnection are retired by 2025.[20] These retirements are in addition to 5.4 GW capacity already announced to retire by 2025, which are also hardwired into the model. As nuclear plants run as baseload with high capacity factors (more than 90% in many cases), we are interested in the role of other fuels and technologies (especially, renewables and natural gas plants) as replacement for the retired nuclear capacity.

2.2.4. Other important assumptions

Besides the key factors discussed above, we also put together the following assumptions applicable to all scenarios.

2.2.4.1. Coal plant retirements. We cross-reference multiple data sources and hardwire 16.4 GW of coal capacity retirement. The majority of these announced coal plant retirements will take place in the Eastern Interconnection by 2020 (Fig. 4). These retirements are often the result of market conditions as well as the cost of compliance with environmental regulations such as Mercury and Air Toxics Standards, Cross-State Air Pollution Rule, coal ash disposal, and cooling water utilization. Since we do not explicitly model these costs, these hard-wired retirements provide an approximation of their potential impact. In the absence of state efforts to save some plants (see endnote 10), we expect that the model would retire more coal capacity at least under some of our scenarios, especially in cases with the lower natural gas price forecast.

2.2.4.2. Cost assumptions for new resource candidates. There are different overnight capital cost (CAPEX) estimates and longer-term forecasts available from various entities, including government agencies, industry consultants, and financial outfits. There is no consensus on future costs, especially for evolving renewable technologies such as solar PV. We adopt base capital cost assumptions for major thermal and renewable generation technologies used by ERCOT in its 2016 Long-Term System Assessment (LTSA) scenarios (Table 1). Note that the real base CAPEX of wind and solar decline significantly whereas real base CAPEX of thermal plants remain the same. ERCOT has one of the lowest cost structures in the country. The model has multipliers for

[19] See Nuclear Energy Institute 2016 Wall Street Briefing. Accessed Sept. 15, 2016 at http://www.nei.org/Issues-Policy/Economics/Financial-Analyst-Briefings/NEI-2016-Wall-Street-Briefing.

[20] Almost two-thirds of 43 GW assumed nuclear capacity retirement is within the PJM territory (28 GW). PJM (2016) forecasts 14 GW of nuclear retirements by 2026 under the "Low Gas Price" sensitivity. Our scenario, albeit aggressive, is not impossible if natural gas prices and, accordingly, electricity prices remain low and out-of-market support mechanisms such as those mentioned in endnote 10 are not adopted more universally.

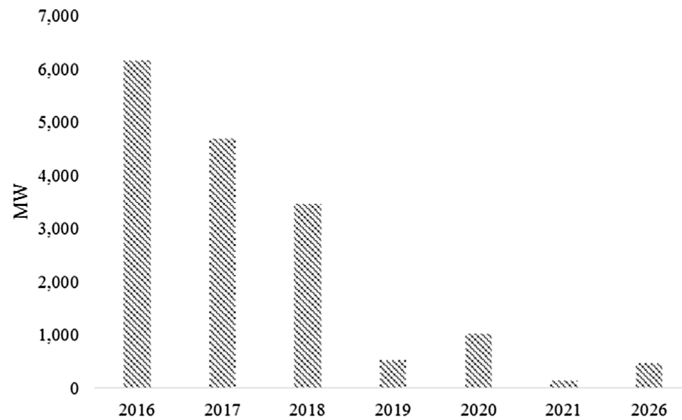

Fig. 4. Hardwired Coal Capacity Retirements.

Table 1
Base Capital Cost Assumption ($2015/kW).

	Gas CC	Gas CT	Coal	Nuclear	IGCC	Wind	Solar PV
2016	1073	791	3202	6395	4307	1682	1541
2017	1073	791	3202	6395	4307	1627	1352
2018	1073	790	3202	6395	4307	1573	1241
2019	1073	790	3202	6395	4307	1521	1191
2020	1073	790	3202	6395	4307	1477	1149
2021	1073	790	3202	6395	4307	1436	1110
2022	1073	791	3202	6395	4307	1395	1074
2023	1073	791	3202	6395	4307	1355	1045
2024	1073	790	3202	6395	4307	1317	1024
2025	1073	790	3202	6395	4307	1280	1005
2026	1073	791	3202	6395	4307	1253	986
2027	1073	791	3202	6395	4307	1226	968
2028	1073	791	3202	6395	4307	1201	950
2029	1073	790	3202	6395	4307	1176	932
2030	1073	790	3202	6395	4307	1151	915
2031	1073	790	3202	6395	4307	1127	898

Accessed at http://www.ercot.com/content/wcm/key_documents_lists/81693/2016_LTSA_update.pptx
Notes: Converted into $2015. CC is combined cycle. CT is combustion turbine. Source: 2016 LTSA Scenario Update, presentation at the ERCOT Regional Planning Group meeting, December 15, 2015.

regional cost variations, which yields higher costs in most other regions.[21]

We convert these overnight CAPEX values into Base Capital Carrying Cost ($/MW-week), an annual value used in model's economic calculations, utilizing appropriate assumptions on debt-equity ratios, corresponding weighted average cost of capital and depreciation schedules for different technologies and accounting for regional variation on labor and material costs.

Furthermore, for new wind and solar resource candidate, we include investment tax credit (ITC) in model inputs as a negative adder for reducing Base Capital Carrying Cost. In addition, we include renewable electricity production tax credit (PTC) with a phase-down schedule as a negative variable cost adder ($/MWh) for existing wind resources pursuant to latest legislation.[22]

Table 2
Model Scenarios.

Scenario	Renewable Capacity	NG Price	Nuclear Retirements
1	Current Trends	Reference	
2	Current Trends	EIA	
3	Aggressive Renewables	Reference	
4	Aggressive Renewables	EIA	
5	Current Trends	Reference	43 GW
6	Current Trends	EIA	43 GW

2.3. Model scenarios

We evaluate six main scenarios for LT resource expansion modeling, based on different combinations of key assumptions discussed earlier (Table 2).

3. Long-term resource expansion modeling results

3.1. Total costs[23]

We first investigate changes in total cost from 2016 to 2030 under different natural gas price scenarios (Fig. 5). Between scenarios 1 and 2 (both with the Current Trends levels of hardwired renewable capacities), although there are regional differences, generally speaking, higher natural gas prices improve economics of coal plants and delay coal retirements, leading to higher coal-fired and lower gas-fired generation.

However, reduction in gas-fired generation is not large enough to offset the impact of higher natural gas prices, leading to an overall increase in fuel costs of about $139 billion. Other cost categories increase by $67 billion from scenario 1 and scenario 2, owing to higher CAPEX ($45 billion) and higher FOM ($22 billion), which result from additional renewables build-out and operating existing coal plants longer and more. These comparisons hold with higher level of hardwired renewable capacities (comparing scenarios 3 and 4): $132 billion increase in fuel costs as compared to $54 billion increase for the sum of CAPEX, FOM, and VOM. This time, CAPEX increases by $34 billion and FOM by $17 billion.

We then examine the impact of higher renewable capacities, while keeping natural gas prices constant across scenarios.

[21] Cost trends might be different across the country (i.e., regional multipliers might change over time). However, this area requires in-depth research, which is beyond the scope of the current analysis.

[22] See U.S. Department of Energy. "Renewable Electricity Production Tax Credit (PTC)." Accessed at http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc; and "Business Energy Investment Tax Credit (ITC)." Accessed at http://energy.gov/savings/business-energy-investment-tax-credit-itc.

[23] Note that our modeling results do not include costs associated with upgrading transmission and distribution systems that might be necessary to accommodate high levels of renewable capacity. For example, Texas spent more than $7 billion over several years on Competitive Renewable Energy Zone (CREZ) lines to accommodate roughly 18 GW of wind capacity in West Texas.

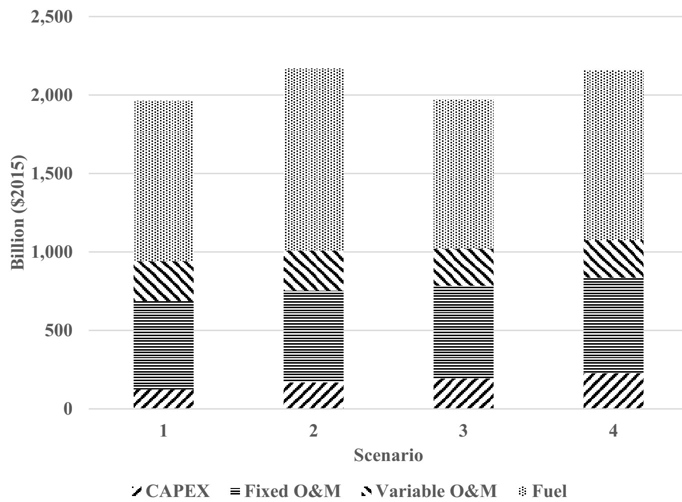

Fig. 5. Total Costs, 2016–2030.

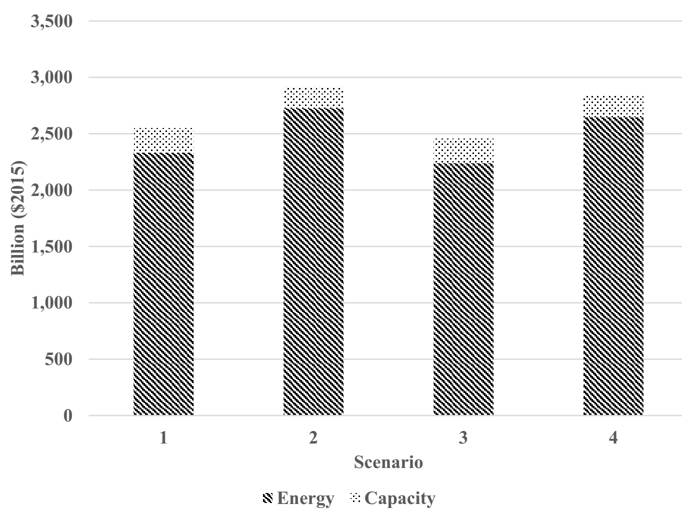

Fig. 6. Total Revenues, 2016–2030.

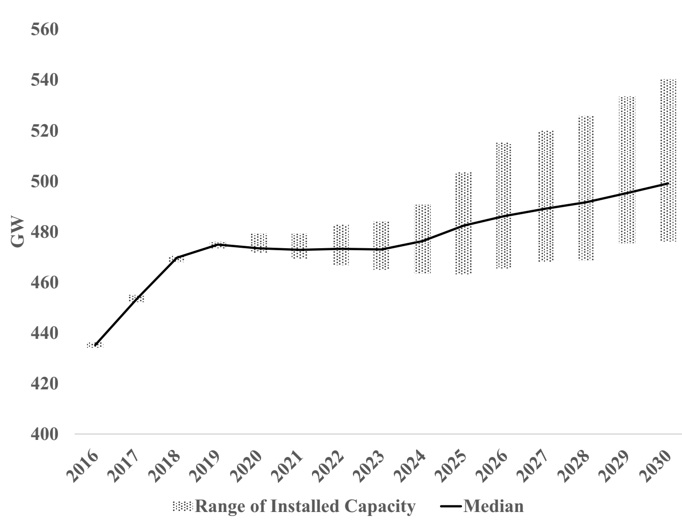

Fig. 7. Range and Median of Natural Gas Installed Capacity, 2016–2030.

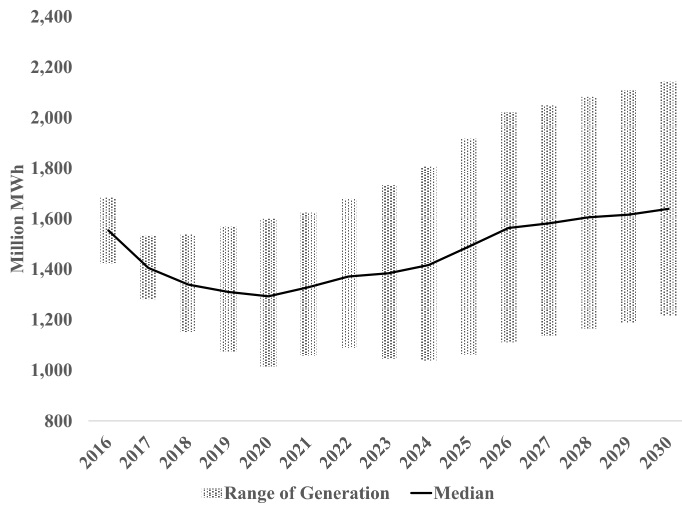

Fig. 8. Range and Median of Natural Gas Generation, 2016–2030.

Comparing scenarios 1 and 3 (both with Reference natural gas price forecast), having more renewable capacity in the system reduces fuel costs by around $74 billion and VOM by $17 billion. However, additional CAPEX ($70 billion) and FOM ($28 billion) offset these savings. With scenarios 2 and 4 (both with the EIA natural gas price forecast), higher natural gas prices further curtail gas-fired generation, but higher penetration of renewables yield only slightly higher savings in fuel costs ($80 billion saving between scenario 2 and 4) as compared to the comparison of scenarios 1 and 3. Again, increases in CAPEX ($59 billion) and FOM ($23 billion) mostly offset the sum of these fuel cost savings and decline in VOM ($14 billion).

3.2. Total revenues

Total revenues received by generation resources include energy and capacity revenues (Fig. 6).[24] Revenues are smaller with high installed capacity of renewables. The average per-MWh price is typically several dollars lower in the Aggressive Renewables scenario versus the Current Trends scenario depending on the zone and the year.[25]

Total revenues between 2016 and 2030 for all generators decline about $91 billion, or 3.6%, from scenario 1 (Current Trends) to scenario 3 (Aggressive Renewables). With high natural gas prices, revenues decline roughly $69 billion, or 2.4% from scenario 2 to scenario 4.

Higher natural gas prices, as one might expect, help increase energy revenues and appear to reduce the need for capacity payments to make generators whole. Capacity revenues, which represent less than 9% of total revenues in all four scenarios, decline $29 billion, or 13%, and energy revenues increase $393 billion, or nearly 17%, from scenario 1 to scenario 2. With Aggressive Renewables, capacity revenues decline $21 billion, or about 10%, and energy revenues increases by about $409 billion, or 18% from scenario 3 to scenario 4.

3.3. Natural gas capacity, generation and usage, 2016–2030

The total installed gas generation capacity increases by about 40 GW from 2016 to 2019, mainly to replace the hardwired retirement of coal capacity, which ranges from 20 to 25 GW depending on the scenario (Fig. 7).

However, generation from natural gas plants does not increase along with additional capacity during the same period. The median of the scenarios declines by about 261 million MWh from 2016 to 2020 (Fig. 8), primarily driven by the results of the scenarios with higher natural gas prices, which encourage higher generation from coal and renewables facilities. During this period, some natural gas plants suffer from low capacity factor and revenues, which induce some retirements as one can observe from the slight declines in median installed capacity in 2020 and 2021 (about 2.1 GW in aggregate; see Fig. 7). Gas-fired unit retirements continue through the mid–2020 s in scenarios with high natural gas prices. For example, in scenario 4, gas retirements total about 10 GW between 2019 and 2025.

The gas-fired generation starts to increase in 2021 (Fig. 8). This increase appears to result from the acceleration of coal capacity retirement, owing to the cumulative effect of the hardwired renewables capacity and new gas-fired builds between 2016 and 2020 (Fig. 7). Gas-fired generation makes up the void left by coal retirements. Average capacity factor increases by at least 2–3% in all scenarios; large amounts of additional gas capacity are not built until late 2020 s in scenarios with high natural gas prices.

Beyond 2022, the range of uncertainty around both gas-fired generation and installed gas generation capacity starts to increase across the scenarios. The retirement of a large amount of nuclear capacity is one of the factors that widens the range. The range of uncertainty is larger for generation output (Fig. 8) than installed capacity (Fig. 7). In 2022, the difference between the maximum and minimum installed gas capacity amounts to 3.4% of total installed capacity, which increases to almost 13% by 2030. In contrast, the generation range represents 43% of total generation in 2022 and increases to 58% in 2026 before settling around 57%. This comparison suggests that there are significant differences across the scenarios with respect to capacity factors of natural gas plants, with the attendant implications on plant revenues and long-term resource adequacy.

From 2022 to 2030, the lower bounds of installed capacity and generation ranges correspond to scenario 4: Aggressive Renewables with high natural gas price (EIA HH price), while the top of the range corresponds to scenario 5: Current Trends with lower

[24] ISOs and RTOs modify capacity markets from time to time. The model approximates the characteristics of capacity markets as they existed before 2015.
[25] With default CO_2 prices, energy prices are higher. The revenues would have increased roughly by $360 to $760 billion depending on the scenario.

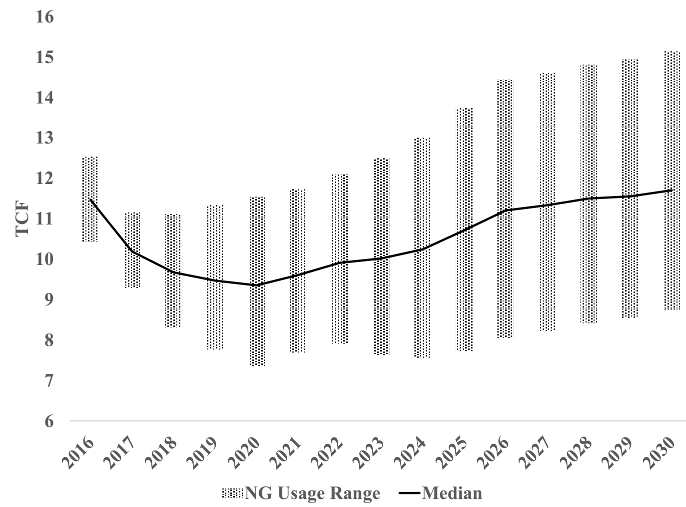

Fig. 9. Range of Natural Gas Usage for Power Generation, 2016–2030.

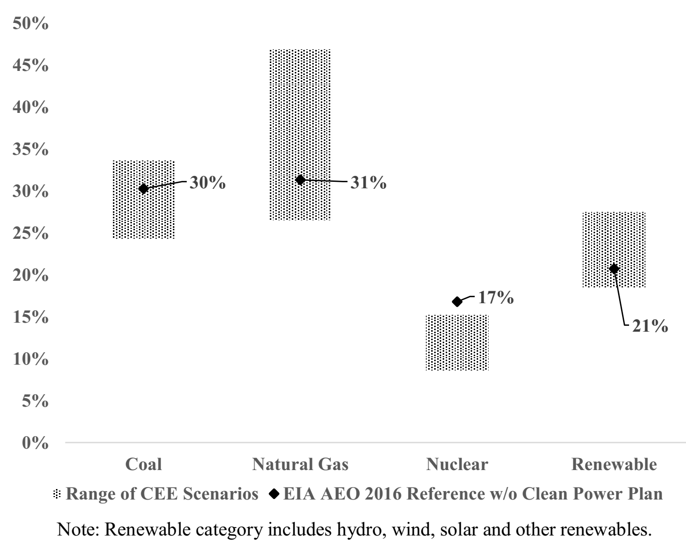

Fig. 10. Generation Share (percentage) by Fuel in 2030.
Note: Renewable category includes hydro, wind, solar and other renewables.

natural gas price forecast (Reference HH price) and large nuclear capacity retirement by 2025.

Our results suggest that accelerated retirement of nuclear plants would deepen reliance on natural gas. The model builds additional 39/25 GW of natural gas, and 16/7 GW of solar under scenario 5/6 as compared to scenario 1/2. In the absence of nuclear retirements, installed gas capacity would still reach around 500 GW in 2030 under both scenario 1 and scenario 3, while the model reduces total gas builds to 487 GW in scenario 2 and to 476 GW in scenario 4 in response to high natural gas prices. Again, these comparisons underline natural gas price as the dominant factor affecting the decision to build new gas generation capacities.

Natural gas burn for power generation follows the pattern of gas-fired generation share (Fig. 9). The lower bound of our estimated range occurs with Aggressive Renewables and high natural gas prices (scenario 4), while the higher bound takes place with Current Trends and low natural gas prices plus nuclear capacity retirement (scenario 5). The continued retirement of coal capacity after 2022 is likely to be the primary driver of sustained natural gas usage for power generation. Our modeling results suggest a range of about 6.4 trillion cubic feet (tcf) of natural gas usage in 2030 (from roughly 8.7 to 15.1 tcf). In fact, this range remains more or less constant after 2025. The natural gas usage reaches 13 tcf in 2030 even without nuclear retirements but with reference gas prices (scenario 1). With EIA Henry Hub price (scenario 2), gas usage would climb back to its 2015 level of 9.5 tcf in 2030, after declining to 8.5 tcf in 2025.[26]

3.4. Generation fuel mix in 2030

As the evolution of natural gas generation is interdependent with other generation resources, we present a “big picture” of generation mix in 2030 resulting from our scenarios in comparison to results from the 2016 AEO (Fig. 10). When assuming no CPP, 2016 AEO forecasts the share of gas-fired generation at about 31% in 2030, closer to the bottom of the range from our scenarios. AEO forecast is most consistent with scenario 2 (Current Trends with

[26] Assuming default CO_2 prices would add roughly 2 tcf of additional gas burn in 2030 to all scenarios.

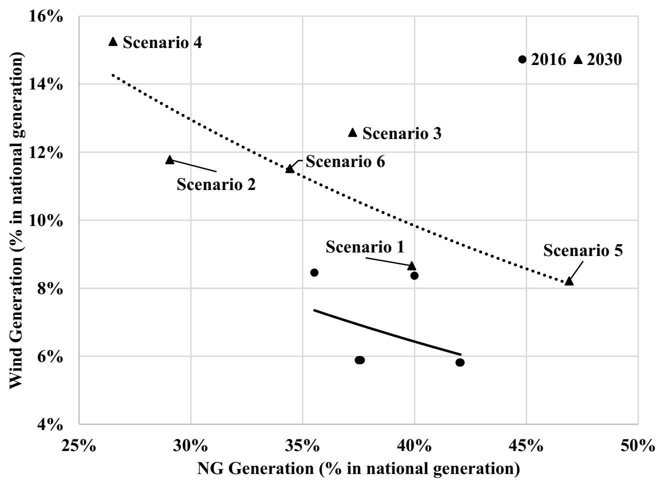

Fig. 11. Natural Gas and Wind Generation Balance.

the EIA natural gas price forecast), in which the share of natural gas in generation is 29%.

In contrast, low natural gas prices (Reference HH price) will push natural gas share to the range of 37% and 40%, depending on different levels of hardwired renewable capacities. The nuclear retirement scenarios push the share of natural gas to 47% with low gas prices but keeps it at only 34% with high gas prices as the combination of nuclear retirements and high gas prices keep some coal generation online at higher capacity factors and encourages slightly larger capacities of new solar and wind.

The lower bound of coal generation (24%) corresponds to scenario 3 (Aggressive Renewables and low natural gas prices), and the upper bound (34%) occurs with scenario 6 (Current Trends, EIA natural gas price forecast, and nuclear retirements). This is consistent with the general notion that less aggressive renewable capacity build-out and higher natural gas price would be the lifeline for coal generation; but it also shows that nuclear retirements could extend the life of some coal plants. The 2016 AEO scenario without CPP forecasts 30% share for coal in 2030, which is consistent with our scenario 4 (Aggressive Renewables and high natural gas prices).

In terms of renewables, hydro accounts for 6.4% without much uncertainty as no large hydro capacity is expected to come online in any of the scenarios. The share of wind generation ranges from 8.2% to 15.3%, and solar generation ranges from 1.5% to 3.9%, depending on the scenario. The share of all renewables in the 2016 AEO scenario without the CPP is about 21%, which is roughly equidistant from all of our scenarios except for scenario 5, which yields the top of our range (27.5%). It is also worth noting that the EIA scenarios consistently yield 17% market share for nuclear generation whereas all of our scenarios, with the exception of nuclear retirement ones, produce a market share of 15.2%.[27]

3.5. Tradeoff between natural gas and wind generation

Between 2016 and 2030, the share of wind generation increases nationwide in all scenarios. The smallest increase occurs in scenario 5 with 2.4% and the largest in scenario 4 with 6.8%. In contrast, the share of natural gas increases only in scenario 5 by 4.9% while it decreases 2% to 9% in other scenarios (Fig. 11). However, given that the very low natural gas prices in 2016 led to historically high market share for gas, this comparison is somewhat misleading. If we compare the share of gas generation in 2017 to that in 2030, except for scenarios 2 and 4 (with high natural gas prices), the share of gas-fired generation also increases. After 2019, the share of gas generation increases in all scenarios over the years.

There is a trade-off between wind and natural gas generation: higher share of wind goes hand in hand with lower share for natural gas. However, the extent of the trade-off is a function of natural gas price and installed renewable capacity. Natural gas share could be nearly 11% lower in 2030 with higher natural gas prices either with Current Trends level of renewables (comparing scenarios 1 and 2) or with higher renewable capacity in the market (comparing scenarios 3 and 4). In contrast, the extent of installed renewable capacity has a less significant impact on natural gas usage. Comparing scenarios 1 and 3 (or scenarios 2 and 4), an extensive renewable resource build-out would reduce the share of gas-fired generation by less than 3%.[28]

These observations are consistent with the notion that, increasingly, gas-fired generation will be needed to provide balancing to variable generation from wind and solar in addition to replacing coal and nuclear as baseload generation. The extent to which this replacement will occur, however, depends on the price of natural gas as utilities can switch to cheaper coal generation as they have done in recent years if the price of natural gas is "too high." Coal and nuclear retirements, if sustained, could increase baseload market share for gas units and could limit gas-to-coal switching capability. The timing and magnitude of any natural gas price increase becomes very important in predicting these trade-offs. Complicating the analysis are the recent efforts by various states to save nuclear units and, in some cases, coal units (see references in endnote10). If successful, these state policies will reduce the relevance of scenarios 5 and 6.

4. Conclusion

Our modeling results suggest that gas-fired generation should continue growing through 2030, even in scenarios with large renewables expansion. Coal retirements and balancing of variable generation from the renewables appear to be the main drivers for these results. However, the range of uncertainty is high: depending on the scenario, 2030 natural gas burn for power generation can be as low as 8.7 tcf or as high as 15.1 tcf. Very low natural gas prices in 2015 and 2016 induced large gas burn levels (9.7 tcf in 2015 and 8.7 tcf in the first 10 months of 2016)[29]; but both price scenarios analyzed in this article presume increasing real prices, which renders 8.7 tcf as a possible outcome with EIA's high natural gas price forecasts and a large build-out of renewables. Overall, the natural gas price has the largest impact on gas burn. Higher gas prices tend to reduce the share of gas-fired generation, which is often replaced by coal and renewables; but the impact on per-MWh revenues is limited.

Although the model does not retire any nuclear plants based on its economic algorithm, recent retirements and announced retirements imply that actual plant economics might be different. Testing a somewhat aggressive scenario of retiring 43 GW of nuclear units by 2025 (in addition to those already retired and

[27] The EIA assumed in AEO 2016 that Diablo Canyon nuclear plant (2.24 GW generating capacity) in California will continue to operate beyond 2025, while we retired this plant per PG&E announcement (endnote 18).

[28] With default CO2 prices, the share of natural gas would be roughly 10% larger in scenarios 1–4; and, the share of wind would be 2–3% smaller.

[29] Data source: EIA "U.S. natural Gas Deliveries to Electric Power Consumers." Accessed Nov. 3, 2016 at https://www.eia.gov/dnav/ng/hist/n3045us2m.htm.

announced to be retired in the near future) underlines the importance of natural gas as an important substitute for baseload generation although nuclear retirements also induce higher coal-fired generation and new wind and solar capacity. Many states started pursuing policies to keep nuclear and coal units online. In future studies, we plan to analyze potential impacts of these policies as well as other changes in energy and environmental arena; however, our current results provide some boundaries in terms of generation mix.

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