CHAPTER 2

The Gas-Power Nexus

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Introduction

The first draft of this chapter was written in early 2018. It is now end of summer 2020, when the COVID pandemic continues to present a range of uncertainties for the global economy. But there have been other developments since the first draft that will have more structural impact on the use of natural gas for power generation than the COVID pandemic, the response to which may strengthen some of these recent trends.

To start with, installed wind and solar capacity increased much more than previously predicted. The developers built 34 gigawatts (GW) of wind instead of 18 GW and 20 GW of utility-scale solar instead of 12 GW. The 2016 extension of tax credits (production, PTC, and investment, ITC) and growing state, city, and local mandates and corporate procurement certainly played a role but the cost declines, especially for solar, have been substantial. Battery storage seems to be following a similar path of mutually reinforcing trends: declining costs and increasing policy support.

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Also relevant are baseload capacity retirements. Coal-fired plant closures between 2018 and early 2020 have been 10 GW larger than previously planned levels. Most of the lost baseload generation was replaced by gas-fired combined cycle units but wind and solar generation also played a larger role than in the past. The future of many coal-fired plants is bleak, but there is now reason to expect more nuclear plants to continue operating longer. In early 2018, many nuclear plants were expected to retire in the 2020s because they had been unable to generate enough revenues in wholesale markets with historically low electricity prices. Only one operator had applied for a license extension to 80 years by early 2018. Then courts supported state efforts to save nuclear plants with zero emissions credits (ZECs) or other mechanisms. Following the court decisions, more states instituted policies to keep nuclear plants online. Now, there are 11 units with about 11 GW of capacity that either received an extension of their operating license to 80 years or are in the process of applying and having their applications reviewed by the Nuclear Regulatory Commission.

In the meantime, challenges to environmental advantages of natural gas as compared to coal have increased. Methane leaks along the oil and gas supply chain infrastructure are the main concern but flaring and venting of associated gas across the low-permeability resource plays around the country also attracts considerable attention. The industry is investing in reducing methane leaks and flaring. There are innovative companies that started deploying 24-hour monitoring equipment. But until these practices become standard for all operators and positive outcomes are transparently and effectively communicated to the wider public, opposition to natural gas will likely spread. In certain parts of the country, local opposition, often organized and supported by national environmental groups, has been able to delay or force cancellation of pipeline projects with increasing success in 2019 and 2020. Prominently, there have been several court decisions that curtail regulatory initiative in permitting and encourage more opposition filings.

In the meantime, a few cities around the country started banning new natural gas infrastructure, including the connection of new homes to distribution networks. These actions are so far limited to only a few locations and several states took action to stop cities from implementing such bans but they have the potential to spread in parts of the country with ambitious decarbonization goals. A central tenet of decarbonization is electrification of energy services commonly provided by natural gas such as space and water heating, cooking, and drying laundry. One might expect electrification to induce demand growth but electricity demand has been fairly stable since the Great Recession of 2008–2009. Electrification is still in its infancy in most areas but the expansion of energy efficiency and conservation programs may also be masking the scale of electrification. As such, higher utilization of gas-fired plants cannot count on load growth. The lack or contraction of gas demand will undermine economics of gas distribution utilities as well as pipeline and storage operators with attendant implications for gas supply contracts of power generators.

These anti-gas trends should be seen as part of the wider issue of climate change, which increasingly influence investors and corporate decision makers. Although not yet dominating their investment decisions, the promotion of environmental, social, and governance (ESG) standards by an increasing number of investment banks and major management consultancies advises caution around bullish power sector gas burn prognostications.

The growing opposition to natural gas, legal barriers to developing gas infrastructure, and rising prominence of ESG also undermine gas use as feedstock for hydrogen. Popular color coding of hydrogen classifies it as gray if derived from natural gas (or blue if associated CO_2 emissions are captured and sequestered) as compared to green if obtained from electrolysis that uses electricity from renewable energy or nuclear. Hydrogen is expensive and energy-intensive to separate from carbon or oxygen, to transport, and to store. Hence, its large-scale penetration is decades away if it is to occur. But the current hype supports a momentum of sorts behind the technology. From the perspective of the power sector, however, hydrogen's role may be worth a closer look. Major gas turbine manufacturers have been able to mix hydrogen with natural gas in power generation with a hydrogen ratio of fuel ranging from 5 to 95 percent. Increasing the share of hydrogen in the mix requires design modifications but seems doable. Already, hydrogen is available as a byproduct of refining and petrochemicals operations; most of it is used within that industrial complex but some can be made available for power generation at a relatively low cost. Still, these conditions exist only in a few locations, which should limit the use of hydrogen in the power sector.

It may be difficult to focus on these trends since the recent growth in gas-fired generation conceals some of their impacts. In 2019, 38 percent of utility-scale generation was from natural gas as compared to 23 percent from coal.[1] As a result, electric power sector natural gas burn increased nearly 50 percent between 2008 and 2019. Nearly two-fifths of the natural gas consumed in the United States[2] is burned for electric power generation, which is now the largest gas market.

However, considerable uncertainty exists about the future gas use in the power sector. Although I acknowledged these uncertainties in early 2018, I was confident about the growing role of gas-fired generation across the country through at least the 2030s and, likely, beyond. Today, I am not as confident about nationwide growth although gas burn growth is still the most likely scenario in many regions. Other regions will continue to move away from all fossil fuels, including natural gas. For example, between 2008 and 2019, gas burn declined 44 percent in California, 14 percent in the New England region, 17 percent in New York, and 16–58 percent in wind-rich Idaho, Kansas, and Nebraska. These trends reflect a combination of factors highlighted above. Any speculation on the future role of natural gas utilization for power generation, certainly beyond the mid-2020s, needs to take the evolution and spread of these factors into account across different regions.

This chapter is an attempt to provide such a holistic analysis. I start with a historical perspective on how and why natural gas became the dominant fuel for power generation. I then provide a SWOT analysis in order to put a structure around the issues highlighted in this introduction. Then, I depict the multiplicity of scenarios for future gas burn in the power sector as defined by four key drivers mined from the SWOT analysis. The rest of the chapter provides details on each driver and trends that influence them. I conclude with an outlook to demonstrate the range of uncertainty.

Resurgence of Natural Gas in Power Generation

Power generation was not always the primary consumer of natural gas. Only about one-fifth of marketed natural gas was used for power generation in the early 1990s. Since the beginning of the twenty-first century, gas-fired power generation has been increasing rapidly building on the momentum gained in the second half of the 1990s (Fig. 2.1). Unlike in the 1990s, when growing demand for electricity encouraged more generation from coal and nuclear as well, the growth of the gas-fired generation fleet has been phenomenal in the new century (Fig. 2.2). The share of gas-fired generation increased from about 12 percent in 1990 to nearly 16 percent in 2000, 24 percent in 2010, and 38 percent in 2019.

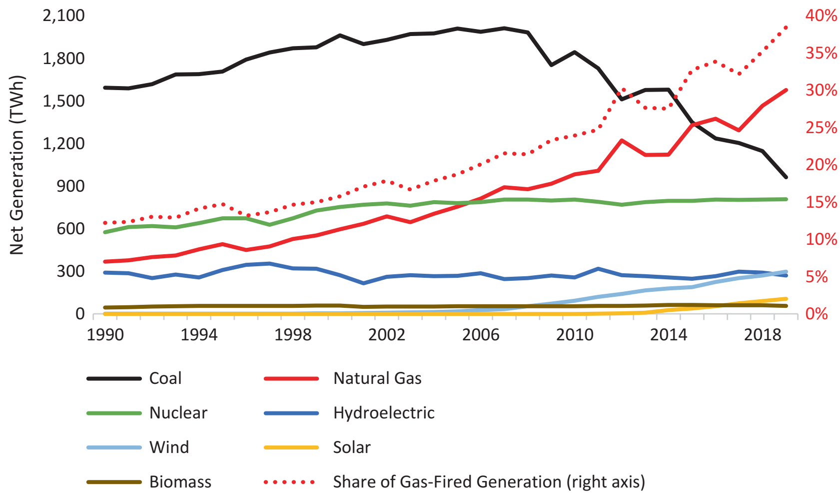

Fig. 2.1 Electricity generation by fuel/technology. (Source: U.S. Energy Information Administration (EIA) data for generation from all sectors. Solar includes the EIA estimate of small-scale solar since 2014. Excludes fuels with minute shares of production (<0.5 percent): petroleum liquids, petroleum coke, other gases, geothermal, and other. Altogether, these fuels account for less than 2 percent of total annual generation since 2008 and less than 1 percent since 2017)

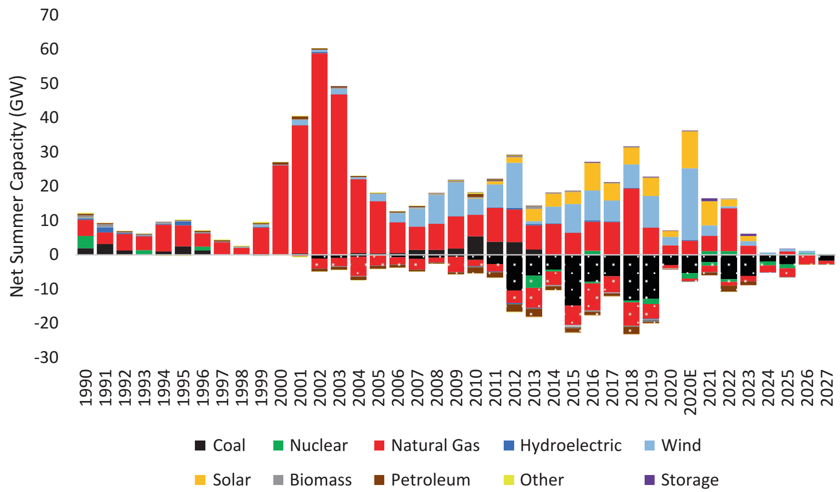

Fig. 2.2 Actual and planned generation capacity additions and retirements by fuel/technology. (Source: Compiled by author from EIA-860 data. Expected capacities for 2020 and beyond include construction completed but not commissioned, under construction, regulatory approval received or pending. Data set for retirements before 2002 is incomplete)

Drivers of Gas-Fleet Transformation and Increased Gas Burn

Three drivers of gas-fired generation growth are worth highlighting. First, the deregulation of natural gas wellhead prices and markets, which started with the passage of the Natural Gas Policy Act in 1978 and continued with various Federal Energy Regulatory Commission (FERC) orders, increased the availability of affordable natural gas by the 1990s.[3] Second, the Public Utility Regulatory Policies Act and Powerplant and Industrial Fuel Use Act of 1978, encouraged nonutility generation, either as combined heat and power facilities built by large industrial consumers, or as new plants built by merchant generators. Finally, natural gas turned out to be a favored fuel for technological and commercial reasons. Merchant generators could build large-scale gas-fired plants cheaper than the avoided cost of regulated utilities and quicker than other thermal plants fueled by coal or uranium. Combustion turbine (CT) plants provided the capabilities to follow load and quickly ramp up or down, valuable features in competitive electricity markets. Improvements in gas turbine efficiencies and combined-cycle gas turbine (CCGT) plant designs rendered natural gas the most efficient fuel to burn for baseload generation.

The restructuring of regulated, vertically integrated utility models into competitive electricity markets fueled much investment in the 2000s: nearly 157 GW of CCGT and 73 GW of CT capacity were added. For comparison, total U.S. installed generation capacity was about 905 GW in 2010. Nearly 26 GW of gas-fired capacity were retired, but more than 70 percent were older steam turbines, and another 20 percent were mostly older CTs. In contrast, new coal-fired capacity additions were only 6.7 GW, compared with 6.1 GW of coal-fired capacity retirements.

While electricity demand grew at an annual average of 2.2 percent in the 1990s, it only grew 0.7 percent in the 2000s partially owing to the Great Recession. Environmental concerns also played a role in reduction of coal-fired generation capacity and its replacement by natural gas and, in some regions, wind. The increased availability of affordable natural gas from low-permeability geologic formations, commonly known as shale gas, became a major factor starting in the late 2000s. As a result, the share of coal-fired generation fell below 45 percent in 2010 from 52 percent in 2000 while gas-fired generation increased its share to 24 percent from 16 percent, more than compensating for the drop in coal's share.

In the 2010s, when electricity demand remained flat, coal lost market share to wind and utility-scale solar in addition to natural gas. Between

2011 and early 2020, operators retired nearly 82 GW of coal, 46 GW of gas, and about 6.8 GW of nuclear capacity while building 90 GW of gas-fired capacity, 67 GW of wind, and 38 GW of utility-scale solar (Fig. 2.2). A lot more wind and solar capacity are expected to be completed before the end of 2020. More than 70 percent of gas-fired retirements were older steam and combustion turbines, nearly 90 percent built before 1980. About 13 GW of other capacity were retired during the same period. Almost all of these “other” plants burned petroleum products. As a result of these changes, the share of coal-fired generation fell to 23.3 percent in 2019 while the shares of gas-fired, wind and solar (inclusive of small-scale) generation increased to 38.2, 7.2, and 2.6 percent, respectively.

Regional differences are important to note for possible implications on natural gas supply chain infrastructure. More than half of the gas retirements since the early 2000s occurred in Texas and California but for different reasons. Lower gas and accompanying low electricity prices drove retirements of older, less efficient steam and combustion turbines as well as some CCGTs in markets already dominated by gas-fired generation, such as Texas. The addition of large wind and solar capacity in California played a major role although wind capacity additions were also a factor in Texas.

A handful of regions hosted most of the new gas-fired capacity built since 2000 led by Texas (13 percent), Florida (10 percent), California (8 percent), and Pennsylvania (6 percent). The Southeast, including Florida, hosted about 30 percent of the new gas-fired capacity. Most of the additions (especially CCGTs) in Texas, California, and the Southeast occurred in the 2000s. In contrast, the states in the largest organized market, PJM Interconnection (PJM), hosted more than 20 percent of new gas-fired capacity, about 50 percent of which were built in the 2010s fueled by the availability of cheap natural gas from the Marcellus shale and the need to replace retired coal-fired capacity.

In summary, the natural gas-fueled generation fleet in the United States has undergone a significant transformation since the early 2000s with new, more efficient CCGTs and CTs replacing older, less efficient CCGTs and steam turbines. The rejuvenation of the gas fleet continues. Nearly 33 GW of new gas-fired capacity are expected between 2020 and 2025 (Fig. 2.2). The majority of future gas builds will occur in the PJM and Southeast regions. About 10 GW of mostly steam turbines are planned to be retired by 2025. As a result, the average capacity-weighted age of the U.S. gas-fired power plant fleet will be around 20 in 2025. But one needs to distinguish between capacity additions and how they will be utilized. In Midwest, California, and New York, many additions are CTs intended for backing up intermittent renewables. Even CCGTs will likely be used more for reliability purposes as coal-fired plants are pushed out and renewables are added rather than consistent baseload generation. In essence, this is the scenario where natural gas is a "bridge" fuel.

Gas-Fired Versus Renewable Energy Capacity Additions

Wind and solar capacity additions have been more than double the amount expected in early 2018. At the time, planned wind and utility-scale solar additions between 2018 and 2020 were 18 GW and 12 GW, respectively. Instead, 34 (20) GW of wind (solar) was built since 2018 with another 6.5 (4) GW expected to be completed by the end of 2020. In contrast, more than 38 GW of gas-fired capacity was expected online between 2018 and 2020 but only 34 GW will be completed by the end of 2020.[4]

Despite the recent surge in wind and solar capacity expansion, the near future is still gas-heavy (Table 2.1). Nearly 29 GW of gas-fired capacity is expected between 2021 and 2023 as compared to 8.7 GW of wind and 15.7 GW of solar. In terms of capacity under construction and with regulatory approvals, gas-fired capacity has a bigger advantage.

However, permitting and construction are faster for wind and solar than natural gas. Given lower costs, more projects are likely to be developed in good resource locations such as the Southwest for solar and east of the Rockies for onshore wind. An extension of federal tax credits, more generous state programs, COVID stimulus targeting clean energy, or, more likely, a combination of these approaches will promote renewables across the country.[5] Probably reflecting these policy drivers, other data sources suggest a more bullish renewable future than the EIA 860 data,

Table 2.1 Expected gas, wind, and solar power plant capacity, GW (2021–2023)

	Natural gas	*Wind*	*Solar*
Under construction	3.9	2.7	2.7
Regulatory approvals received	8.1	<0.1	4.0
Regulatory approvals pending	7.6	2.2	3.9
Planned	9.4	3.8	5.2

Source: EIA 860 March 2020

which are based on surveys and EIA research. For example, American Public Power Association (APPA; Zummo 2020), using the ABB Velocity Suite database, reports nearly 15 GW of gas, 20 GW of wind, and 10 GW of solar capacity as under construction, some of which already came online in the first half of 2020. But Zummo (2020) also reports 18 GW of gas, 13 GW of wind, and 10 GW of solar as permitted; and 14 GW of gas, 24 GW of wind, and 28 GW of solar with pending applications. The shift toward wind and solar is even stronger with the proposed plant data: 66 GW of wind and 64 GW of solar versus 27 GW of gas. Much of the proposed capacity will not be built any time soon, if at all. Still, as compared to previous APPA reports, the shift in these numbers away from gas toward wind and solar deserves to be taken seriously.

The capacity in interconnection queues of system operators provides another perspective on intentions of developers. In 2019, total capacity in queue was 265 GW solar, 215 GW wind, 97 GW solar with battery storage, 9 GW wind with battery storage, 48 GW standalone battery storage, and 76 GW natural gas.[6] Again, most of the capacity in queue will not get built right away, if at all, even if they receive their interconnection permits. Most importantly, new transmission infrastructure is needed in many locations. But the large discrepancy between gas and renewable energy capacities is strong evidence of energy transition in the power sector. These trends also signal that utilities and regulators are becoming more focused on low capital cost projects that can be developed relatively quickly rather than long-lead, capital-intensive projects.

Coal Retirements

Nearly 90 GW of coal-fired capacity has been retired since the early 2000s, 90 percent of which occurred in the 2010s.[7] Environmental regulations such as Mercury and Air Toxics Standards (MATS), increasing belief in a sustained period of low natural gas prices, and rising penetration of wind and solar all contributed to decisions to retire uneconomic plants. Actual retired capacity has consistently surpassed planned retirements throughout the 2010s but 2019 was still a surprise (Fig. 2.3). The early 2020s are promising to be another period of large coal-fired capacity retirement.

The increased supply of natural gas from low-permeability resources has been the main cause of low electricity prices, as gas-fired generation is often the marginal generator setting the price in competitive electricity markets. Figure 2.3 depicts three series of natural gas prices for power

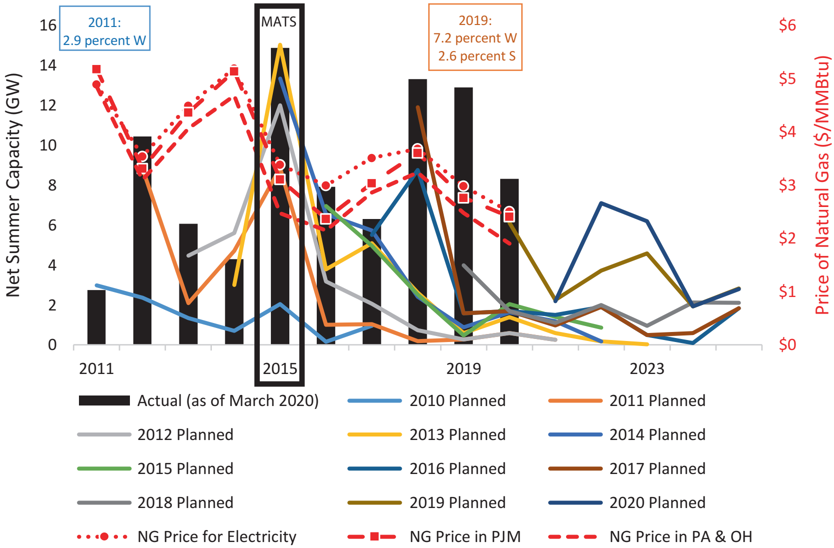

Fig. 2.3 Actual and planned coal-fired plant retirements (net summer capacity). (Source: Compiled by author from data reported in EIA-860 monthly spreadsheets except for the natural gas price for power generation from EIA natural gas price data. MATS: Mercury and Air Toxics Standards. Percentages for wind (W) and solar (S) in 2011 and 2019 are national averages of generation inclusive of small-scale solar PV in 2019. 2020 retirements are the sum of 2.94 GW already retired and about 5.4 GW expected to retire in EIA 860 March 2020 report)

plants: an average U.S. price, an average of prices in six states that make up the great majority of the PJM market (home to a third of the coal retirements), and an average of prices in Pennsylvania and Ohio, where more than 21 percent of the coal retirements occurred. The PJM territory covers all gas production from the Marcellus shale. On average, gas prices in the PJM region have been 5–10 percent lower than the U.S. average price; the gap is much larger for the Pennsylvania–Ohio region. Nearly 40 percent of the coal retirements in 2018 happened in the Electric Reliability Council of Texas (ERCOT) market, where natural gas prices have also been lower than the U.S. average.

Increasing penetration of wind and solar lowered prices further in some markets. The low dispatch cost of renewables will continue to put downward pressure on wholesale electricity prices, which has become a concern for all generators, including operators and developers of renewable energy facilities (see the "Clean Technology Penetration" section for details).

Although MATS was the most influential environmental regulation driving retirements through the 2015 compliance year, other regulations targeting regional haze (ozone), cooling-water use, and coal-ash and combustion-residual management have played a role in decisions to retire particular plants. Some utilities made the necessary investments to render some coal-fired plants compliant with MATS and other regulations. Others could not justify investing in equipment to comply with these regulations in a low-price environment. In essence, these environmental regulations expedited the exit of older, less efficient units. More than three-quarters of coal units retired in the 2010s were built before 1970 and had historically low or declining utilization.

SWOT

With a young fleet of efficient plants ready to replace retiring baseload generation with low-cost electricity fueled by a relatively clean-burning fuel with a low price, the power sector is primed to burn more natural gas in the future. But a SWOT analysis is useful to balance the fuel's technical and economic strengths that laid the foundation for its current dominant position in the generation portfolio with its weaknesses—mainly environmental in nature—that lead to threats in policy, regulatory, and public acceptance space. Yet, the natural gas industry also has opportunities that can be realized primarily, albeit not uniquely, by proactively abating environmental risks (Table 2.2).

Table 2.2 SWOT—Natural gas burn for power generation

Strengths: *Cheap, efficient, baseload, dispatchable, scalable, fits existing grid, much cleaner than coal*	**Weaknesses:** *Methane leaks, flaring, combustion emissions, hydraulic fracturing impacts, price uncertainty and volatility, too much competition among generators*
Opportunities: *Reducing methane leaks and flaring, remaining low-cost, improving efficiency, feedstock for and co-firing with hydrogen*	**Threats:** *Expanding policies & local opposition to block gas infrastructure, growing financial & public support for wind, solar, storage & other alternatives*

Strengths

Natural gas burns much cleaner than coal. The fuel offers a tremendous improvement over coal in terms of local emissions that cause many illnesses: no mercury emissions, negligible emissions of sulfur dioxide and particulates, and lower emissions of nitrogen oxides. There is also no solid waste such as coal ash. Also, combusting gas for power generation emits up to 50 percent less CO_2 than combusting coal, which can be reduced further with carbon capture and sequestration (CCS) but at a considerable cost.

The natural gas price has been low enough to generate baseload electricity cheaper than coal since the mid-2010s. Some regions benefited from even lower prices (e.g., the Marcellus region). Given the abundance of the resource not only in North America but also globally, the price of natural gas should remain in a range that makes it attractive for power generation for the foreseeable future. The gas turbine technology is advanced, but improvements in turbine and combined cycle power plant designs can raise conversion efficiency that allows for the cost of electricity to remain low even at higher natural gas prices.

Plants can be built relatively quickly at reasonably low capital cost in locations fit for replacing retired baseload units without significant, if any, investment in grid expansion. Importantly, existing capacity is sufficient in most regions for years to come. Increasing the utilization of existing CCGT plants by a few percentage points should suffice to compensate for lost generation from 28 GW of coal and nearly 6 GW of nuclear capacity scheduled to retire by 2025. All regions have flexible gas-fired plants such as CTs that are currently best resources to provide backup generation to intermittent wind and solar facilities.

It is difficult for wind and solar to replace retirements one-to-one for mainly three reasons. First, the locations of coal and nuclear retirements and the locations of best wind and solar resources do not overlap in most cases. Second, availability of wind and solar generation does not overlap with load profiles in most regions. Third, once adjusted for intermittency, depending on location, their utilization of nameplate capacity decreases to roughly 35–55 percent for wind and 20–35 percent for utility-scale solar. Taken together, these shortcomings necessitate the building of two to five times more capacity than the dispatchable thermal plants being replaced. Moreover, to maximize their utilization and to increase their match to load profiles, the facilities should be geographically distributed, which requires additional investment in the transmission grid. All of these additional investments increase the unit cost of renewable energy delivered to customers, often above the cost of competing technologies such as CCGTs (see the "Potential Potholes for Further Expansion of Renewable Energy" section for a more detailed discussion of system integration costs).

Weaknesses

Large amounts of installed capacity and rising share of generation does not mean high utilization of all plants. In a previous rapid expansion period, a large wave of construction added many new gas-fired plants. At the peak construction period between 2000 and 2005, nearly 206 GW of new gas-fired capacity were added. But in following years many gas-fired plants struggled commercially in many locations. A growing number of state and federal programs encouraged the expansion of renewable energy technologies and undermined the market share of gas-fired plants. Low natural gas and, hence, electricity prices in competitive markets worsened the profitability of many plants.

But the most important reason for commercial difficulties faced by gas-fired power plants was the intense competition among generators that caused lower utilization of even the newest plants, some of which often did not receive proper compensation owing to poor market designs (e.g., energy price caps). In hindsight, capacity expanded too much in the 2000s, encouraged by the low-interest-rate environment, expectation of continued load growth, encouragement of generous capacity compensation schemes, or some combination of these factors in competitive wholesale electricity markets. The low electricity prices since the early 2010s have caused bankruptcies and consolidation in the merchant sector.

History may repeat itself. Electricity prices remain low partially due to low price of natural gas but also because of excess generation capacity in many markets. The retirement of much of the baseload capacity offers an opportunity for newer gas-fired generation to fill the gap, but there is too much capacity being built in some regions. One driver of this potential overbuild is the confluence of capacity mechanisms that encourage some older plants to stay online while also inducing new builds, and government incentives to promote wind and solar farms and to prevent retirement of uneconomic nuclear plants.

The tensions over market design issues and out-of-market policies among various stakeholders in organized electricity markets have been rising for some time. Federal and state policymakers and regulators are increasingly at odds with each other. Some states threaten to leave organized markets. I expect generation portfolios in most regions to be determined increasingly by state policies rather than markets. State mandated portfolios will exclude gas-fired units as long as they are not needed for supply security and reliability.[8]

Although the price of natural gas is forecasted to be low for years to come, its history is one of volatility. The boom-bust cycles are common for natural resources. Low prices encourage demand but discourage upstream investment to prove up more reserves. This cycle eventually leads to supply constraints and higher prices. However, the cycle may be broken in the United States because of associated gas. Since the early 2010s, the price of natural gas remained low despite decreased drilling for dry gas because the supply of associated gas from low-permeability plays rich in liquids has been significant once midstream infrastructure was developed to allow market access. As such, oil prices have become a key influencer of the natural gas supply and hence its price in North America (see Chap. 1 for extensive treatment). Oil prices have been even more volatile than natural gas prices. The mitigation of this price risk has been a key justification of utilities for signing long-term power purchase agreements (PPAs) with wind and solar developers at prices above wholesale market prices. Long-term stability of electricity costs provided by PPAs has value to utilities and their customers. Such PPAs are increasingly seen as a better way of securing sufficient generation capacity in power systems than ill-designed and oft-challenged capacity compensation schemes.

But there is a more pervasive reason why states, cities, utilities, and corporations are willing to announce net-zero targets within the 2030–2050 timeframe and sign 100-percent renewable energy contracts. Nominally, that reason is climate change but other environmental and local economic concerns are pertinent from the perspective of public opinion that doubtless informs policy and influences companies' public relations messaging. For example, the labor intensity of wind and solar installations as well as energy efficiency retrofits and the fact that these jobs are local have been instrumental for garnering support of more state representatives to pass aggressive clean energy targets. Similarly, some nuclear plants are saved by state initiatives partially to preserve economic benefits they provide to host communities.[9]

Although not always observable in their investment decisions, the promotion of ESG standards and decarbonization by an increasing number of investment banks signal potential difficulty of financing fossil fuel projects, including natural gas infrastructure, in the future.[10] There is a movement toward developing standards to include emissions in traditional financial reporting of publicly traded companies.[11]

In short, the main weakness of natural gas is that it is a fossil fuel that causes climate change. The fact that it releases about half as much greenhouse gas emissions as coal when combusted for power generation is not satisfactory to a growing portion of the public and, as a result, policymakers. Increasingly, methane leaks along the supply chain and flaring of associated gas concern the environmental community. Risks of groundwater contamination, earthquakes, increased truck traffic, local emissions, and other environmental and social impacts associated with hydraulic fracturing are still relevant although they are not the headline nowadays. These environmental concerns establish the foundation of main threats to natural gas.

Threats

The social license to operate (SLO) is becoming harder to obtain for natural gas infrastructure, including gas-fired power plants and pipelines, in many locations. Some states have been able to block new pipelines using a variety of tools at their disposal, often challenging FERC, and ban new gas-fired power plants or force the retirement of older units, replacing them with renewables, energy efficiency and conservation, battery storage, or a combination.

Local opposition can also cause costly project delays and may have become more impactful as a result of a D.C. Circuit Court of Appeals ruling from mid-2020 that forces FERC to end its decades-long practice of delaying decisions on rehearing requests by landowners or other stakeholders regarding infrastructure projects such as pipelines under the Natural Gas Act. Some legal experts consider this decision a milestone with potential implications for power sector projects under the Federal Power Act. This ruling is just one of the many recent court decisions that make getting permits for natural gas infrastructure such as pipelines more difficult.

This growing anti-gas movement gains in significance when seen within the context of energy transition. There are now examples of utilities cancelling permitted natural gas projects. Instead, utilities focus on technologies mandated by states. Utilities' ability to include the state-sponsored assets in their cost base for regulatory approval is a catalyst for such transformation of utility portfolios. This strategy also appears to shelter incumbent utilities from smaller competitors implementing more distributed technologies.

But also important are declining costs and increasing popularity of alternative technologies. Years of incentives, technological advances, and globalization of supply chains brought down the per-MWh cost of new wind and solar farms to beat the cost of new gas-fired generation in locations with good wind and solar resources and ready access to transmission and distribution (T&D) grids. The cost of battery storage seems to be following a similar decline curve. Cost declines make it easier for states to mandate even larger shares of these technologies. Continuing federal tax credits make these resources even more palatable. This feedback loop among cost declines, public opinion, and policy is critical for future expansion of clean technologies.

Distributed resources add more complexity to energy transition. Some customers seem to be showing more interest in rooftop solar and battery storage for their homes or businesses but also in smart appliances and ability to respond to price signals. More than 30 states have renewable portfolio or clean energy standards (RPS and CES), ranging from 10 to 60 percent by 2030 (80–100 percent by 2050 in several states). Despite its now well-known cost-shifting and other regulatory problems, 40 states have mandatory net metering rules to promote rooftop solar. More states are expected to follow in the footsteps of seven states with energy storage targets, which also offer financial incentives for storage installations. Overall, there are several thousand policies and incentives across different levels of jurisdiction that support utility-scale or distributed renewable energy (with varying technologies eligible as renewable energy in different jurisdictions), storage (mostly battery), energy efficiency, electrification, and other clean energy projects.[12] All of these changes signal a fundamentally different electric power system, in which the role of gas-fired generation will change and gas burn will likely shrink.

But adding a large amount of intermittent and variable resources into electricity grids either in utility scale or as distributed energy resources (DER) brings about system integration costs from building T&D facilities to compensation of units that can provide backup and grid reliability services. Even energy efficiency programs show up as a cost in customer bills. These costs have been rising, which may offer an opportunity for natural gas.

Opportunities

The retail cost of electricity, inclusive of all charges in a bill (energy, T&D, renewable, energy efficiency, etc.), has been rising in many states in a widening path of divergence from wholesale electricity prices, which have been declining since the early 2010s. The decline was driven mainly by low natural gas prices and, in some markets, low-cost, subsidized wind and solar generation. Generally, retail costs increased more and fastest in some of the states with large renewable energy mandates and other clean energy programs while they remained flat in states with low clean energy targets or none.

The increasing cost of energy transition started to attract more attention in political discussions with a particular focus on energy justice implications. Low-income consumers, for whom the share of energy bills in disposable income is high, are voicing their concerns via consumer organizations. It is not clear, however, whether this issue will gain sufficient traction in policy debates. Even if it does, the cross-subsidization of utility rates—a common regulatory practice for decades—may be a relatively easy solution to protect low-income customers. Public support for energy transition is strong and has been rising. The lack of pricing environmental externalities of fossil fuels has been a successful counterargument in the past in response to higher cost of integrating intermittent and variable wind and solar technologies to power systems. Enough customers may be willing to cross-subsidize low-income consumers as long as the transition does not jeopardize reliable delivery of electricity. Hence, whether the mass media coverage of rising energy costs, if it ever happens, will lower the support for energy transition policies enough to matter is unclear.

On the other hand, the goals for energy transition are becoming greater in many regions. Adding more wind (especially offshore), solar (especially rooftop), battery storage, and charging infrastructure for electric cars, and implementing more energy efficiency programs in a more compressed timeline will add to the costs more visibly. Similarly, a carbon fee will raise the cost of electricity right away. In the absence of alternative ways of paying for these costs, rising customer bills will certainly induce more consumers calling their representatives.

However, the natural gas industry cannot and should not wait for these external developments to result in its favor. The industry needs to change the perception of natural gas as an environmentally harmful fossil fuel with proactive elimination of its externalities. There is already movement in detecting and stopping methane leaks across the supply chain. These efforts must continue with demonstrable results. Operators should continue to reduce flaring without waiting for regulations. Hydraulic fracturing and its limited environmental impacts are better understood by more of the public as a result of outreach campaigns but work is not finished. Similarly, the industry should not shy away from promoting the substantial benefits of natural gas in reducing local pollution (mercury, particulate matter, sulfur dioxide, nitrogen oxides, coal ash) when it replaces coal. Critically, the communication of best industry practices, self-regulation efforts, and fuel's benefits has to be honest, transparent, and constant.

The low-price, low-demand environment caused by the COVID pandemic created a survival instinct for many companies and probably pushed mitigation of environmental impacts down the list of priorities. But mitigation is not optional if the industry is to enhance its public acceptance across wider geographies. Inherent strengths of natural gas as a cheap and versatile fuel that is cleaner burning than coal are not sufficient to guarantee its future share in power generation. The electric power sector has many alternatives, albeit often costlier, and is experiencing a significant transition not only in terms of utility-scale generation technologies that garner more policy support every day but also on the consumer side with a growing demographic of prosumers adopting modern technologies to generate, store, or manage their electricity.

Drivers of Future Gas Burn for Power Generation

Will the share of gas-fired generation continue to increase as it has over the last three decades? It is tempting to extrapolate the upward trend seen in Fig. 2.1. However, four drivers extracted from the SWOT analysis may stimulate or hinder future gas burn: natural gas price, baseload capacity retirements, penetration of clean technologies, and difficulty of obtaining SLO. The first two are straightforward but last two are composites that require some explanation.

- Clean technologies include the usual suspects such as wind, solar (utility-scale and distributed), and energy storage technologies but also demand side technologies such as smart thermostats and appliances, heat pumps, and others that are mostly leveraging advances in digital technology. The collection of these technologies allows for visions of micro grids and virtual power plants (VPPs) that signal a more efficient system with control of more distributed resources to optimize generation and consumption of electricity in real time.

- Difficulty of obtaining SLO is meant to capture all kinds of environmental regulations at different levels of government that does not directly impact the price of natural gas,[13] legal and regulatory changes that increase the cost of the permitting process, and local opposition to infrastructure.

In Fig. 2.4, I offer an admittedly limited 2-D visualization of the combined influence of these four drivers on future gas burn relative to 2020

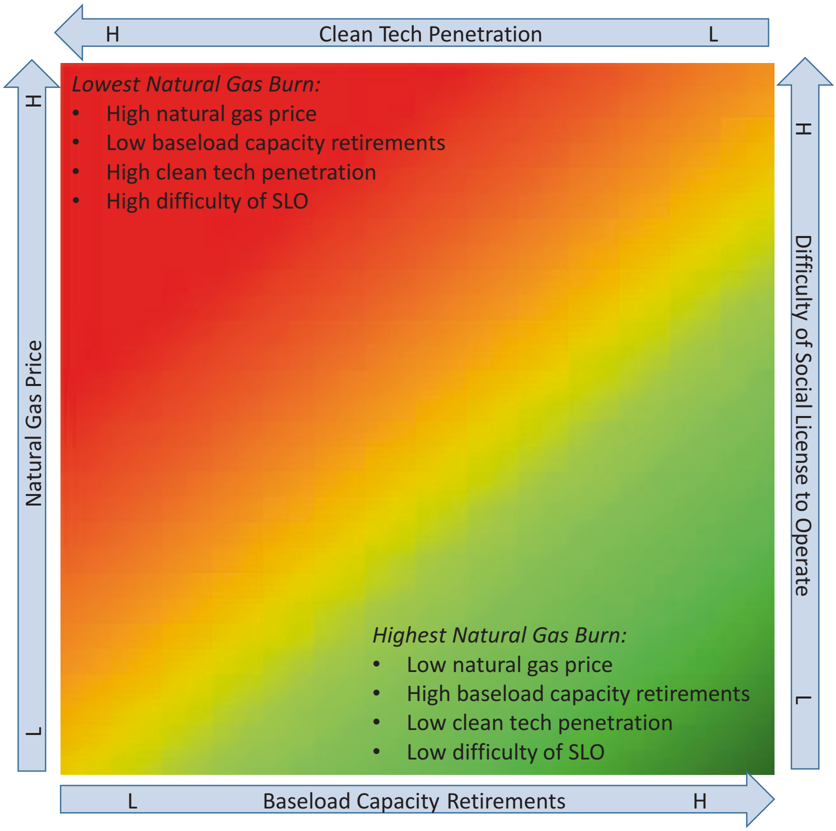

Fig. 2.4 Key factors driving natural gas burn for power generation. (Note: Arrows indicate direction of increase from low (L) to high (H), all relative to current state (2020). See discussion of internal dynamics and external forces throughout this chapter)

level. These drivers are interdependent. For example, higher natural gas prices would likely encourage deployment of more clean technology, especially utility-scale wind and solar generation facilities. Somewhat counterintuitively, higher natural gas prices may also help economics of baseload plants, including CCGTs, to generate more revenues from higher wholesale electricity prices. All else being equal, lower gas prices would produce opposite effects.

The graphic can be interpreted for any point in future. Although one might expect some drivers to follow recent trends (e.g., clean technology penetration to continue rising), others will likely be more volatile (e.g., natural gas price, baseload capacity retirements). I expect natural gas burn to increase through 2025 (lower right-hand corner) because it is highly likely for natural gas price to remain low, for more coal and nuclear plants to retire, for renewable energy penetration to fall short of fully compensating for baseload retirements, and for SLO to remain regionally constrained. But the uncertainty increases beyond 2025. With most likely baseload retirements out of the way, more clean technology online, and SLO becoming more difficult to obtain in more locations, gas burn may start moving toward the upper left-hand corner by 2030. This move will be more visible if natural gas price rises. On the other hand, if the natural gas industry is able to reclaim its SLO while keeping the cost of supply relatively low, natural gas may maintain its share in power generation. And, in the 2030s, nuclear plant retirements may increase as more units will have 60-year licenses expiring and a new wave of coal-fired plant retirements may occur, which is inevitable, even with CCS, given the old age of the coal fleet. The loss of generation from such extensive baseload capacity closures will likely require CCGTs filling the void even with high clean energy penetration in the 2020s.

There are other factors not directly visible in Fig. 2.4. Some are secondary to the four factors depicted; others exert uncertain influence on gas burn; and many are policy or technology drivers, specifics of which are yet unclear (Table 2.3).

Table 2.3 Examples of factors excluded from Fig. 2.4

Secondary	Oil price, environmental regulations that increase cost/price
Uncertain influence	Distributed gas-fired generation
Unclear external policies	Electrification (load growth)

- Oil prices high enough to encourage liquids-directed drilling increase associated gas production and put downward pressure on natural gas prices and upward pressure on drilling costs, both of which disadvantage operators in dry gas plays. At the time of writing, the COVID-19 pandemic is leading to a significant decline in upstream activity in the United States. This lower level of activity is reducing associated gas production that may eventually lead to a recovery in the price of natural gas once the demand starts increasing. On the other hand, a recovery in oil price may encourage liquids-directed drilling and associated gas production once again.
- New environmental regulations on water or chemical use in, or an outright ban on, hydraulic fracturing will increase the cost of natural gas production.
- A CO_2 price should help gas replace more coal-fired generation, but it will also increase the cost of gas-fired generation and the cost of natural gas production and delivery due to methane leaks along the supply chain unless the leaks are prevented.
- A ban on flaring and venting of associated gas can push natural gas price higher or lower depending on capacity of midstream infrastructure. If there are no midstream bottlenecks, more associated gas will reach the market, putting downward pressure on the natural gas price.
- Distributed gas-fired generation via microturbines or reciprocating engines could change the dynamics of gas burn, but its net impact is uncertain, as distributed gas-fired generation can reduce the need for gas-fired peakers.
- U.S. electric-power demand has remained fairly flat since the early 2000s, albeit with significant regional differences. Energy efficiency and conservation measures, along with increasing penetration of behind-the-meter generation and storage, will continue to temper load growth for wholesale generators. On the other hand, electrification of transportation and building use (e.g., space and water heating) could reverse the downward trend of load growth. The specifics of how load growth will influence natural gas use in power generation will depend on energy versus peak load growth, impact of new technologies on power systems and traditional load profiles, and cost and policy trends of technologies such as battery storage and heat pumps.

Before I provide a detailed discussion of the drivers in Fig. 2.4, a brief discussion of some modeling results is useful to highlight not only the importance of input assumptions but also relevance of drivers that are not easy to include in models.

Results from Long-Term Capacity-Expansion and Economic-Dispatch Modeling

Between 2011 and 2017, we have analyzed numerous long-term scenarios via economic-dispatch and capacity-expansion modeling for the ERCOT market and nationwide (e.g., Gülen and Soni 2013; Gülen and Bellman 2015; Tsai and Gülen 2017a).[14] Consistently, our modeling resulted in more gas-fired generation capacity in the future, about two-thirds CCGTs and the rest CTs. Generally, business-as-usual scenarios led to large coal retirements with additions of small amounts of new wind and solar and more CCGTs. We also developed scenarios with large amounts of hard-wired wind and solar because federal tax credits and state mandates continued to encourage their development. In some cases, we also assumed declining capital costs for wind and solar. These scenarios yielded more CTs and fewer CCGTs than the business-as-usual scenarios but still more CCGT capacity than renewables. Importantly, gas-fired generation did not always increase at the same rate as gas-fired capacity, depending on load-growth assumptions, natural gas basis differentials, and, to a lesser extent, the share of other generation sources, including coal and nuclear.

Figure 2.5 is a version of Fig. 9 in Tsai and Gülen (2017a). This version includes the impacts of CO_2 prices. The wide range of gas burns reflects our particular focus on four drivers (consistent with those in Fig. 2.4): capacity and pace of wind and solar buildout, natural gas price paths, large nuclear retirements, and CO_2 prices that would result from the implementation of Clean Power Plan (CPP) starting in 2022. The lower gas-burn levels result from scenarios with faster penetration of larger quantities of renewables (57 GW of wind and 20 GW of solar hardwired to be online by 2022) and higher natural gas prices [$4–$5 per million British thermal units (MMBtu) in real terms] but without CPP and new nuclear retirements (bottom of patterned bars). Lower natural gas prices ($3–$4/MMBtu in real terms) and lower wind and solar buildout (11 GW of wind and 7 GW of solar hardwired) encourage more gas burn.

The most significant jumps occur with CO_2 price increases, which induce coal retirements, and hardwired early nuclear retirements. Nuclear

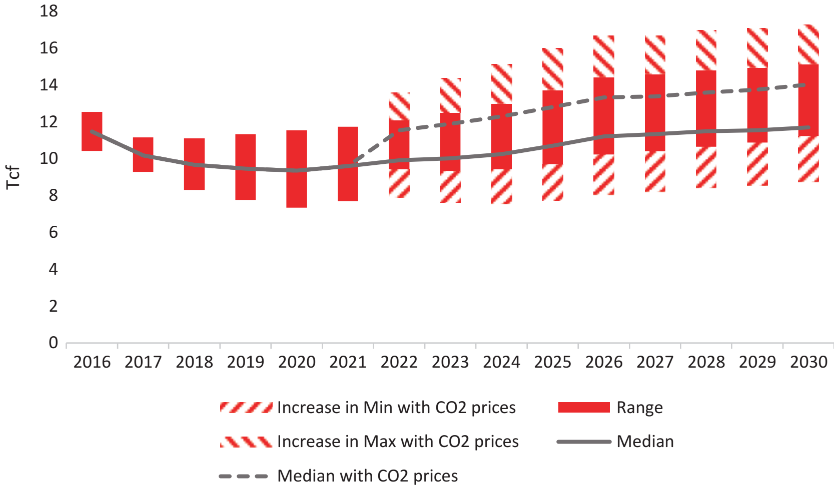

Fig. 2.5 Scenarios of natural gas burn for power generation. (Source: Summary from long-term capacity-expansion modeling using Energy Exemplar Aurora software. Modified from Tsai and Gülen 2017a)

retirements push gas burn to the tops of the red bars in Fig. 2.5. CPP-induced CO_2 prices would force more coal retirements and further increase gas burn to within the range covered by the top patterned bars.

The real world supports our ranges. In 2019, nearly 11 trillion cubic feet (Tcf) of natural gas was utilized for power generation, higher than the median (9.5 Tcf) of our modeling but lower than the top of the range (11.3 Tcf).[15] This larger natural gas burn is due to much larger coal-fired capacity retiring between 2016 and 2019. However, since 2015, replacement of coal-fired generation by gas-fired generation has been less than one-to-one (Fig. 2.6), with wind and solar claiming some of the market share lost by coal because a lot more wind and solar capacity were added. Actual and expected wind capacity additions between 2016 and the end of 2022 are 63 GW for wind and 50 GW for solar as compared to 57 and 20 GW in our modeling.

Recall the discussion of anticipated large renewable capacity adds in the "Gas-Fired Versus Renewable Energy Capacity Additions" section. Wind and solar will compensate for a growing share of retiring baseload capacity. Some simple calculations, albeit ignoring power system realities across regions,[16] is illustrative. Based on the planned coal and nuclear retirements

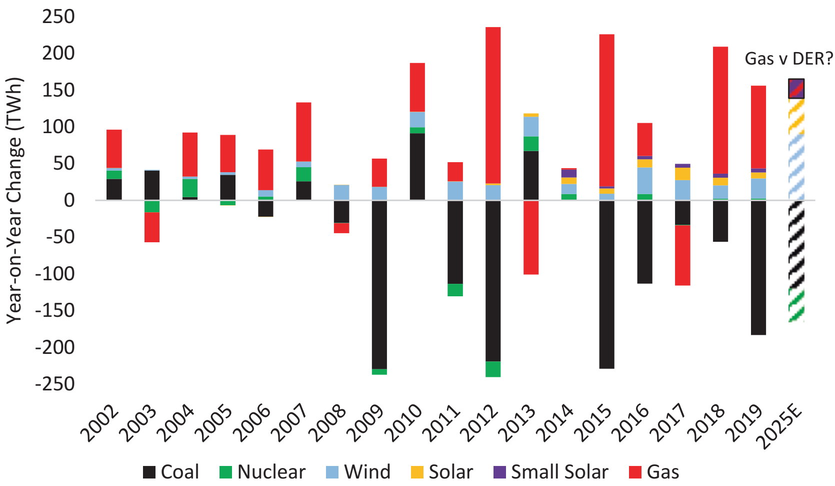

Fig. 2.6 Change in generation. (Source: Author calculations based on EIA net generation data downloaded from EIA data browser. For 2020–2025 see the discussion associated with Table 2.4)

between 2020 and 2025, using recent average capacity factors for each type of facility, coal and nuclear generation will decline by about 119 and 46 TWh respectively.[17] Increasing the capacity factor of CCGT fleet existing at the end of 2019 by only 4 percent will compensate for this loss of baseload generation (165 TWh). This would translate into an additional gas burn of 1.2 Tcf, or an increase of over 10 percent from 2019.

However, expected utility-scale wind and solar facilities, some of which are already under construction, can generate 90 and 49 TWh, respectively, using recent national average capacity factors of 35 and 24 percent (Table 2.4). If all wind and solar expansion were to occur in regions with coal and nuclear capacity retirements (a crucial but unrealistic assumption), the need for additional gas-fired generation would be only 26 TWh (Fig. 2.6). There is no reliable data on planned distributed solar capacity but according to EIA data, small-scale solar has been adding about 5 TWh a year since 2015. If this trend continues, small-scale solar may add 25 TWh by 2025, which would negate the need for additional gas-fired generation, again assuming that small-scale solar will get developed in locations with baseload retirements (see patterned boxes on top of the last column of Fig. 2.6).

Table 2.4 Replacing coal and nuclear generation retiring in 2020–2025 (TWh)

	Coal	*Nuclear*	*Gas*	*Wind*	*Utility solar*
2019 generation	964	809	1579	299	72
2025E change in generation	-119	-46	26-165?	90	49

Source: Author calculations from EIA net generation data downloaded from EIA data browser and EIA 860 data

Clearly, the locations of wind and solar additions and coal retirements will not be a good match. As discussed before, most coal retirements are occurring in regions without great wind and solar resources but with access to cheap gas (e.g., Pennsylvania, Ohio). In contrast, largest solar and wind additions were in locations with better resources such as Arizona, California, Florida, North Carolina, and Texas for solar; and Iowa, Kansas, Oklahoma, and Texas for wind. Also, from the perspective of system balancing in real time (i.e., generation matching load at all times), the intermittency and variability of wind and solar do not allow for a one-to-one replacement of baseload coal-fired capacity even if they are connected to the same grid. On the other hand, tax credits and state mandates continue to encourage the development of wind and solar facilities in sub-optimal resource locations, including regions with baseload retirements. This is especially true for distributed solar. Although these facilities have even lower capacity factors than the national average, grid expansion is making more of wind and solar generation available across larger regions that undermine gas-fired generation.

Overall, gas-fired generation should still replace a considerable share of lost baseload generation in most regions. The existing fleet can replace lost generation simply by raising utilization of existing plants by a few percentage points. However, nearly 33 GW of new gas-fired capacity is expected to come online by 2025, mainly in the same regions as retirements. If the load remains flat as it has in the 2010s, there is a risk of excess capacity just like the experience in the 2000s. As a result, some gas-fired plants may be challenged to generate sufficient revenues.

In addition to wind and solar expanding much more than we modeled, our nuclear retirement scenarios now appear to be premature. Some of the expected nuclear retirements are likely to be postponed beyond 2030 since states save plants with out-of-market compensation (see "Nuclear Revival?" section). In contrast to renewables and nuclear, gas-fired plants depend on market price signals or utility planning.

It is difficult to capture the evolution of this policy space or the growing anti-gas movement and ESG activism in modeling exercises. But it is important to acknowledge that other modeling exercises demonstrate the technical feasibility of reliable grid operations almost exclusively with today's renewable energy technologies. There is much debate about the practicality of such model results and the cost of such systems; most models focus on power system technical capabilities and avoid total cost calculations. But their existence influences policies and regulations that attempt to accelerate the transition to a decarbonized electricity grid.

With this background on key drivers and what modeling suggests about their impact on future gas burn, it is time to deepen the discussion on key drivers, their interactions, and secondary or tertiary factors that can influence their future evolution.

A Wide Range of Uncertainties

It is necessary to set the context for discussing drivers of gas burn by acknowledging regional differences across electricity systems. To begin with, although gas deliveries for power generation increased at the national level, there are several regions where they declined. For example, in California, they declined nearly 50 percent since 2008 as a result of strong policies and regulatory programs favoring alternatives. Many states mimic California in their pursuit of decarbonization. These changes have been forcing organized markets to tweak their designs to ensure proper compensation of resources for the services they provide to maintain grid reliability and resource adequacy.

The developments in regulated utility territories appear more orderly and predictable than developments in organized markets, where the dynamic environment of market design changes has the feel of whack-a-mole, because new adjustments are constantly needed as earlier modifications lead to distortions and complaints by market participants. For example, California programs targeted higher shares of renewables, including distributed generation, gave customers more choice in self-generation and demand response, and encouraged electrification of the transportation sector.[18] For some time now, state regulators have been concerned about another energy crisis (similar to the 2001 meltdown) resulting from the collision of uncoordinated policies. This portfolio of policies has been forcing thermal generation, including natural gas facilities, out of the market. But, California Public Utilities Commission (CPUC) raises concerns about the negative impact on reliability of retiring gas-fired plants and opposition to new fast-ramping gas-fired units (Colvin et al. 2018). Concerned, CPUC is pursuing new policies to require all load-serving entities to hold three- to five-year capacity requirements, which can be met jointly via a central buyer structure. With these policies, CPUC is hoping to keep some thermal plants online in locations critical to grid reliability and resource adequacy until alternatives are in place (e.g., see Randolph 2018).

Other concerned regions started to save some plants (mostly nuclear) with out-of-market support mechanisms (see the "Baseload Capacity Retirements" section). This multijurisdictional policy and market-design space has been evolving over the 2010s. It is setting states against FERC and, in some cases, against each other. Most states prefer mandating specific capacities of specific technologies to reach their decarbonization goals rather than saving markets by pricing various attributes of different technologies such as environmental externalities and reliability. The role of natural gas in this transition is highly uncertain in some regions. Is it a "bridge" fuel, mostly as a supporter of intermittent renewables? Or, will it play a longer-term role as a baseload generation fuel? I remain mindful of this electricity market context as I turn to several factors that will determine gas burn for power generation through 2035.[19]

Natural Gas Price

The natural gas price remains the major determinant of gas-fired generation in the short-term. Historically, coal price has been stable and natural gas price has been volatile. This difference has led to constant switching between baseload coal and gas-fired units to minimize total cost of electricity in real-time operations. There are regional, real-time operation considerations but roughly speaking, as long as the cost of gas delivered to power plants remains below \$3.8/MMBtu, CCGTs generate electricity at a lower average cost than coal-fired plants (see ovals in Fig. 2.7). CTs always cost more than coal or CCGTs but do not compete with baseload plants, as they are needed for load following and real-time balancing of demand and supply (see "Disruptive Technologies" section for a comparison to battery storage costs).

Another driver of CCGT's competitiveness is its lower fixed operating and maintenance cost. Finally, the improvement of average efficiency of the gas fleet as more-efficient plants replaced older units played a role. The average heat rate—a metric of power-plant efficiency measured in heat content of the fuel burned to generate one unit of electricity—for the natural gas fleet (inclusive of CCGTs and CTs of all ages) declined from about 8.5 British thermal units (Btu) per MWh in the early 2000s to about 7.7 Btu/MWh by the mid-2010s. Modern CCGTs have design heat rates of below 7 Btu/MWh. In contrast, the coal fleet average heat rate is about 10 Btu/MWh.

Regional Differences

However, regional fuel costs, average capacity factors, and heat rates may deviate from the U.S. averages represented in Fig. 2.7. The rate of wind and solar penetration also matter for decisions regarding which generator to run at any time during the day across the seasons. A closer look at generation data from ERCOT reveals the complexity of coal–gas switching

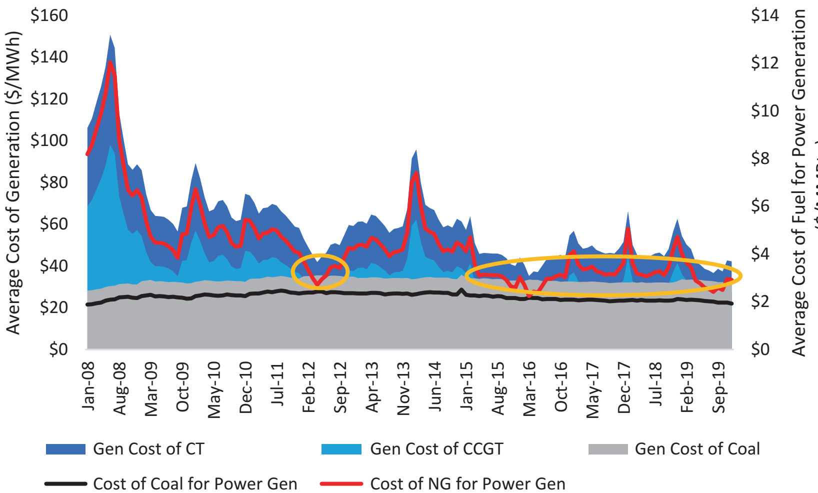

Fig. 2.7 Average coal and natural gas cost to power plants and generation costs. (Source: Generation costs are calculated by author using average fuel costs for power generation from EIA data browser, average capacity factors from various issues of EIA's Electric Power Monthly, average heat rates from EIA-860 Annual Electric Generator Report, and fixed and variable operating and maintenance cost estimates within the ranges provided in Lazard (2019a). CT: combustion turbine. CCGT: Combined-Cycle Gas Turbine. Ovals highlight periods when CCGT generation cost is lower than coal-fired generation cost)

dynamics due to the increasing share of wind and availability of local and cheap gas and lignite supplies. For example, the increasing price of natural gas in the early 2010s reduced the share of gas-fired generation while boosting coal-fired generation (Fig. 2.8). In contrast, the declining price of natural gas from early 2014 appears to have forced the share of coal-fired generation to decline. But the share of gas-fired generation stabilized although the price of natural gas continued to decline. Certainly, changes in electricity demand across seasons, locational considerations for grid reliability, and transmission grid congestion play a role in generation decisions. But, rapid expansion of wind generation after the Congress extended PTC in 2016 has eaten into potential market share of gas. Without the declining natural gas price, gas-fired rather than coal-fired generation could have been reduced. As the natural gas price started to rise in April 2016, coal regained market share.

But revenues were still not sufficient to prevent the retirement of more than 4 GW of coal-fired capacity in early 2018. The share of gas-fired generation increased from 38 percent in 2017 to 47 percent in 2019 while the

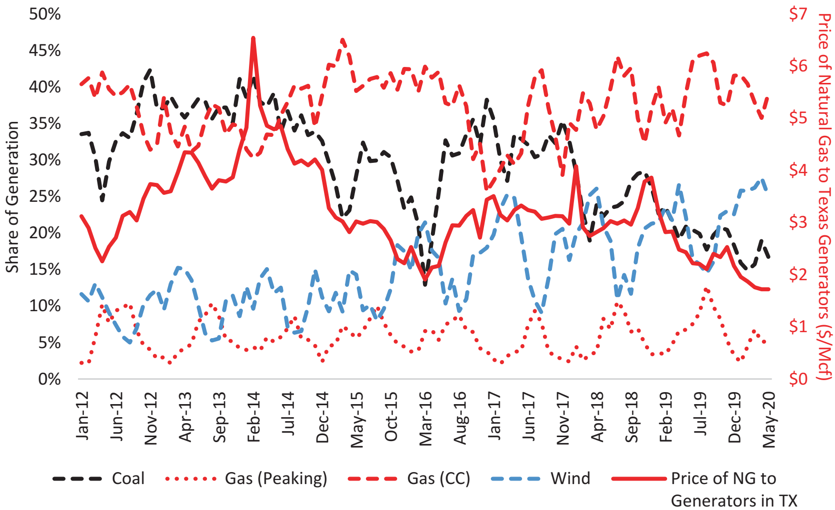

Fig. 2.8 Share of fuels in ERCOT generation (January 2012–May 2020). (Compiled by author using ERCOT fuel mix data (http://www.ercot.com/gridinfo/generation). Natural gas price to generators in Texas from various issues of Electric Power Monthly of EIA)

share of coal declined from 32 percent in 2017 to 20 percent in 2019. Most of the increase came from CCGTs that replaced lost coal-fired generation. The switching in 2019 is driven by continuing decline in natural gas price. The share of wind generation increased to 19 percent in 2018 and 21 percent in 2019, which is probably contributing to increasing utilization of gas-fired peaking, or load-following, units, the share of which reached 7 percent in 2019.[20] Notably, the increase in gas-fired generation came almost exclusively from existing gas-fired plants increasing their capacity factor.

Nationwide, the share of total natural gas delivered to power plants fluctuates seasonally. The correlation between the natural gas price and gas delivered to power plants between January 2002 and March 2020 averaged -0.5 with some seasonal volatility (e.g., lower correlation in summer months). In summer months, the share of gas in generation reaches 50 percent then falls to the 20- to 25-percent range during winter. But regional differences matter. For example, the 2014 “Polar Vortex” increased heating demand for natural gas by residential and commercial customers and reduced gas availability for power generation in parts of the Northeast. In contrast, in Pennsylvania between April 2015 and November 2016, the price of natural gas delivered to power plants remained much lower than national averages, averaging $1.83/MMBtu.[21] Consequently, not only gas-fired generation increased, often replacing coal-fired generation, but also 8.5 GW of new gas-fired capacity started operating in Pennsylvania alone between 2016 and 2019, and another 3.8 GW are expected by 2022. Other PJM states added about 11 GW of gas-fired generation between 2016 and 2019 and expect to add another 4.1 GW by 2025. Almost all of this capacity consists of modern CCGTs.

Given these trends, gas burn may increase in ERCOT and other regions with large coal-fired capacity retirements even at higher natural gas prices than those seen in the second half of the 2010s. Because CCGTs will be the only dispatchable option to compensate for lost baseload generation. This is particularly true for the early 2020s. In regions where large-scale wind and solar penetration are not feasible due to low wind speed and low solar insolation, or transmission grid constraints, the advantage of CCGTs is likely to persist through the 2030s. Existing CCGTs can readily increase their utilization from the current mid-50-percent range by a few percentage points where needed.

Natural Gas Demand in Other Sectors

The future path of natural gas price also depends on demand from other sectors, including exports. Competition from heating customers, who often get priority access to natural gas during tight market conditions such as extreme cold fronts, may occasionally constrain how much gas can be burned by power plants. Although these impacts are seasonal and mostly limited to a few regions (Northeast in particular), restrictions on new natural gas infrastructure (often in the same regions) may increase the frequency of gas shortages for power plants. On the other hand, decarbonization and electrification efforts may reduce the residential and commercial sectors use of natural gas, which has been flat. Such reduction, while freeing gas for power generation, also supports decarbonization efforts. Hence, there is little prospect for gas demand growth from residential and commercial consumers.

The industrial sector's demand for natural gas has been inching up toward 30 percent of total consumption since the development of low-permeability resources increased supplies and lowered prices. While there are alternatives to gas-fired generation such as coal, nuclear, and—increasingly—wind and solar, the alternatives to natural gas as industrial feedstock are limited, at least for certain processes such as methanol and fertilizer production. Nevertheless, industrial gas demand growth in the 2010s has been relatively small (less than 1.7 Tcf—see Chap. 3) and the potential for future growth remains constrained by competing petrochemicals capacity build-out in other parts of the world as discussed in Chap. 3.

In contrast, increasing availability of sizable liquefaction and pipeline export capacity offers a potential outlet for up to 10 Tcf by the late 2020s (EIA 2020). Pipeline exports to Mexico and Canada reached nearly 8 Bcf/d in 2019. Since most natural gas sold outside of North America is indexed to oil price, it may be possible for U.S. liquefied natural gas (LNG) exports to compete globally at prices too high for competitive domestic power generation. As discussed earlier, gas deliverable to power plants below $3.8/MMBtu renders gas-fired generation competitive. In some systems and certain times of the year, even higher prices are acceptable to power plants. These higher prices could still attract global buyers of U.S. LNG and petrochemical products depending on the price of oil and competition from other LNG and petrochemical capacity developers.

However, global natural gas market conditions change rapidly as new resources and markets are developed. Furthermore, in many of the emerging markets gas competes with coal and renewables in power generation, and with liquids in industrial uses. So, U.S. LNG exports may be challenged at times. The COVID pandemic, though unprecedented, demonstrated the competitive weakness of U.S. LNG in a global market with excess supply of natural gas and low oil prices. Despite the availability of 10Bcf/d of liquefaction capacity, U.S. LNG exports fell to 2–3 Bcf/d range by mid-2020.

Natural Gas Price Outlooks

Modeling by the EIA considers the complex interactions among the sectors discussed above as well as various energy and environmental policies, and provides us with ranges of future natural gas prices. For example, 30 scenarios included in the EIA 2018 Annual Energy Outlook (AEO) (2018a) forecast the price of natural gas delivered to electric power plants in a range from about \$3.8/MMBtu to \$7.0/MMBtu in 2019 dollars between 2020 and 2030. The low end of the range (lines in green tones) follows a fairly flat trajectory, while the high end (lines in orange tones) follows a rising path (Fig. 2.9). Lowest prices occur in four scenarios, all with high oil and gas

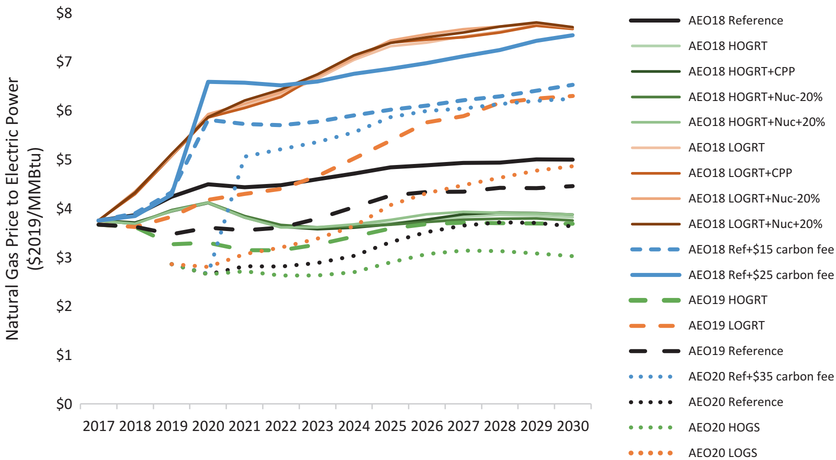

Fig. 2.9 AEO outlooks for natural gas price to electric power (\$2019/MMBtu). (Note: Not all AEO scenarios and all years are represented. LOGRT = low oil and gas resource and technology; CPP = Clean Power Plan implemented; Nuc-20 percent and Nuc+20 percent = 20 percent lower or higher nuclear costs, respectively; Ref = reference; HOGRT = high oil and gas resource and technology; HOGS = high oil and gas supply; LOGS = low oil and gas supply)

resource and technology (HOGRT) assumptions. In contrast, highest prices occur in four scenarios that assume low oil and gas resource and technology (LOGRT). The scenario with a $25 per ton carbon-allowance fee yields a price path similar to ones from these LOGRT scenarios even with gas resources higher than levels assumed in the LOGRT scenario.

Markedly, natural gas price forecasts in AEO 2019 (EIA 2019) declined from comparable scenarios of AEO 2018 and AEO 2020 (EIA 2020) registered further decreases. These declines reflect primarily the improved understanding of natural gas supply from low-permeability plays. They are so substantial that the AEO 2020 low oil and gas supply (LOGS) price for 2030 is lower than AEO 2018 reference-case price. Even a $35 carbon allowance fee scenario in AEO 2020 leads to prices around the AEO 2019 LOGRT scenario.

One does not have to take these price outlooks literally; but the range of natural gas price forecasts do highlight the importance of the oil and gas resources and the technological ability of the industry to deliver those resources.

However, there are many uncertainties on the supply side. Shale operators have struggled with profitability, almost since inception of these plays and through the 2010s. Associated gas production from liquids-directed drilling suppressed natural gas prices and curtailed drilling for dry gas. As detailed in Chap. 1, "gassier" operators—those for whom natural gas is 50 percent or more of production—tend to be lower cost but less valuable based on earnings (expressed as earnings before interest, taxes and depreciation, depletion and amortization, EBITDA). During 2018, EBITDA for gassy players ranged from $1 per thousand cubic feet of natural gas–equivalent (Mcfe) to $2.70/Mcfe.[22] Their annual costs ranged from about $1.60/Mcfe to $3/Mcfe, placing inordinate pressure on hedging (as described in Chap. 1) and other sources of revenue (NGLs uplift, as discussed in Chaps. 1 and 3, and midstream operations, as discussed in Chap. 1). It has become more difficult for operators to find cheap capital. If interest rates rise or oil and gas assets remain less attractive to investors, the cost of capital may rise further. The difficulty of raising external capital, upon which so many producers depend, will curtail capital investment. A combination of factors could push the breakeven price that operators need to support new natural gas-directed drilling to above $3/Mcfe, to $3.50/Mcfe, and perhaps even higher.[23] Since gas-fired generators can access the fuel with only a small premium above these breakeven prices in resource regions (e.g., PJM that sits on top of the Marcellus play, ERCOT in Texas with its large portfolio of plays, and the Southeast in close proximity of several plays), gas will remain very competitive. Even in regions where the cost of gas to electricity generators can be 20–30 percent above these breakeven levels, gas-fired generation looks attractive.

However, beyond the next several years, the price outlook is less certain. If the natural gas prices to end-users rise high enough, higher-priced electricity would encourage investment in alternative technologies. The timing of these demand-supply cycles is central to future gas burn for power generation. For example, rapid rise in natural gas price could delay some baseload capacity retirements and encourage federal and state support for CCS. On the other hand, higher electricity prices can also help gas-fired generators that currently suffer from low revenues, especially in some regions, to increase their earnings even if they generate the same amount. But the current near-term price outlooks do not support such a scenario.

Baseload Capacity Retirements

At the time of writing, nearly 26 GW of coal-fired and 5.7 GW of nuclear capacity are planned to retire by 2025 in addition to more than 80 GW of coal-fired and 6.8 GW of nuclear capacity that retired in the 2010s (Fig. 2.3). Planned coal retirements have been increasing; 2020 announcements are even larger than 2019 announcements which were already significantly larger than previous years. The average age of the remaining coal fleet is about 45. Average age of capacity retired each year has been around 50 since the 2000s. There is already 40 GW of coal-fired capacity that is older than 50 with an average of 9 GW to be added to the 50+ club every year through 2035 (Fig. 2.10). The nuclear fleet is younger but by 2030, 60-year licenses will start expiring for a growing number of units.

The location and utilization of a plant are important factors in retirement decisions. But, in an environment of low natural gas price and growing penetration of wind, solar, and energy storage, aging coal-fired plants are more likely to lose market share and revenues. There are also more environmental concerns with aging plants, especially if their owners did not invest in state-of-the-art emission controls. Hence, I expect the 2020s to witness at least as many coal retirements as the 2010s. However, there are efforts to delay retirement of baseload capacity.

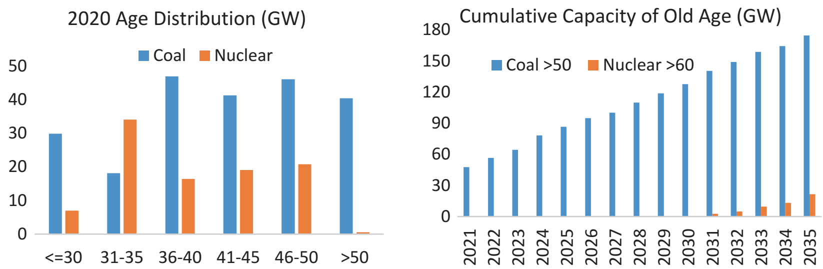

Fig. 2.10 Aging coal and nuclear fleets. (Source: Author calculations from EIA 860 data)

Coal-Fired Capacity Beyond Saving?
Efforts to save coal-fired plants have faltered so far. For example, Ohio regulators approved PPAs for the existing coal and nuclear assets of FirstEnergy and AEP Ohio, but FERC blocked the PPAs in early 2016. In 2017, the U.S. Department of Energy (DOE) asked FERC to devise a mechanism to value "resiliency" of baseload plants that could store fuel on site. FERC rejected the DOE proposal, which was opposed by many market participants. The Administration came back with a bailout of select coal and nuclear plants based on Section 202 of the Federal Power Act. This plan called for the federal government to buy electricity directly from specific generators for two years. The plan was stillborn due to strong and widespread opposition from market participants and other stakeholders.

Despite the failures so far, battles continue in different fronts. In summer of 2020, Wyoming regulators initiated an investigation of the utility plans to retire some coal units. The conflict seems to be between saving local jobs and out-of-state corporations. PacifiCorp—parent of the local utility—also operates in California, Oregon, Washington, Idaho, and Utah, most of which have ambitious decarbonization and renewables goals.

There is also a more pseudo-market approach to saving baseload plants rather than any specific unit owned by a specific utility. Organized markets have been revising their capacity market schemes to provide sufficient compensation to baseload units. But these technocratic fixes by system operator staff have been mired in an environment of conflict between states that want to add wind and solar to their grid and FERC that wants to maintain a resemblance of competitive markets.[24] These capacity markets have been keeping too much existing capacity online while encouraging too much new capacity: reserve margins in markets such as PJM, New York, and New England are significantly larger than target levels.[25] These conditions reduce energy revenues and eventually lead to retirement of many baseload plants, mostly coal-fired.

Nuclear Revival?

Nuclear retirements have been mostly driven by poor economics. Since nuclear plants have been operating at about 90-percent capacity factor[26] and supplying nearly 20 percent of electricity in the United States (Fig. 2.1), they are most easily replaced by CCGTs, as our dispatch modeling confirmed when we assessed retiring 43 GW of nuclear capacity by 2030 (Fig. 2.5). Our scenario was supported by many studies. For example, PJM (2016) forecasted 14 GW of nuclear retirements by 2026 under their low gas price–sensitivity case. Szilard and others (2017) concluded that 63 (36 merchant, 19 regulated utility, and 8 public power) out of 79 units would have lost money in competitive markets in 2016, but additional revenue of $15/MWh would have returned all but ten units to profitability. Market developments supported these studies' findings. In the 2018 PJM capacity-market auction, 7 GW of nuclear capacity did not clear the market.

In response to the retirement risk of zero-emission generation facilities that also create a lot of jobs and sustain local economies, states started developing initiatives to save them. First movers, New York and Illinois, created subsidies for some nuclear plants scheduled to retire in 2017 or 2018. These states felt it necessary to offer credits ranging in value from $10/MWh to $17/MWh (consistent with the findings of Szilard and others 2017) to prevent the premature retirement of nuclear plants. While competitive generators and ratepayer groups challenged these initiatives, courts upheld 2016 initiatives by New York and Illinois. FERC claimed that it, rather than the courts, had the authority to assess whether ZECs were consistent with "just and reasonable" rates in wholesale electricity markets. So far, FERC did not challenge these programs. New Jersey, Connecticut, Pennsylvania, Ohio, and other states either created similar support mechanisms or are considering them.

Perhaps encouraged by such support initiatives by states, more nuclear operators applied to the Nuclear Regulatory Commission (NRC) to extend their operating licenses to 80 years. As of mid-2020, NRC renewed licenses for 4.1 GW in two plants, and was reviewing another application for 1.7 GW with three more applications expected for a total of about

5.3 GW. More plants may pursue license extensions to 80 years. But current market conditions challenge the financial viability of these plants, especially if their license extension requires large capital investments (e.g., due to aging equipment) to qualify. Luckily for these plants and their operators, many states pursuing decarbonization policies are realizing nuclear plants' value as generators of large amounts of baseload, zero-carbon electricity, without which they are unlikely to achieve their decarbonization goals. Subsidizing existing nuclear plants is a cheaper way to keep emissions low than building a large amount of new wind, solar, and storage capacity and investing in the T&D network to accommodate these facilities.

Also, despite significant delays and cost overruns with associated regulatory battles, new nuclear capacity of 2.2 GW will come online in the early 2020s. But this expansion has to be contrasted with the mid-construction cancellation of a major project in South Carolina and cancellation of other projects over the last decade. These experiences highlight the difficulty of a nuclear revival: very high capital cost, 10–15 years from planning to operation, lost capabilities of big engineering firms due to lack of nuclear construction in decades, and shortage of public acceptance.

There is some optimism about the advanced nuclear technologies. For example, NuScale's small modular reactor is expected to receive its NRC license in 2020 and its first plant is reportedly on track for operation in 2027. There are other advanced nuclear designs. Most promising ones are small units that can be deployed much quicker than the traditional nuclear units without the same level of safety and waste concerns. Some can be fit for distributed use in mini grids. There are also federal tax credits available to new nuclear capacity; and Congress has been considering other initiatives to support nuclear technology research, development, and deployment. However, it is highly unlikely for advanced nuclear to play a significant role before the late 2030s.

Overall, multijurisdictional and multipronged efforts to save nuclear and, to a lesser extent, coal-fired plants continue. To the extent these efforts are successful, they will lead to less gas burn. Some gas-fired assets in regions with delayed retirements and low electricity prices may become stranded even if they are relatively young. Nevertheless, aging baseload capacity, especially coal-fired plants, cannot be saved forever. Unavoidable retirements present an opportunity for CCGTs that will only grow toward 2030 and beyond. However, clean technologies have significant potential to undermine this opportunity.

Clean Technology Penetration

Clean technology penetration is complex because it is a composite of multiple drivers, including the usual suspects of wind, solar, and storage but also many technologies to empower consumers to produce their own energy and respond dynamically to prices by managing their consumption, and other technologies that can help utilities improve their management of the T&D grid. Overall, they have the potential to change the electric power industry fundamentally from the model of large generation facilities connected via an expansive T&D network to one where smaller generation and demand-side resources in mini grids are managed by prosumers. Examples can be found around the world. Clean energy portfolios implemented via integrated resource plans (IRPs) propose systems without any gas-fired or any other thermal generation (e.g., Dyson et al. 2018). Their collective impact on gas burn is negative.

Nevertheless, this transition is slow and full of obstacles (see the "Disruptive Technologies" section). For the purpose of this analysis, focusing on wind and solar should be sufficient to highlight the risk to gas-fired generation's market share. About 31 GW of wind and 23 GW of solar was built between 2016 and 2019; and 32 GW of wind and 27 GW of solar are expected to come online by the end of 2021 (Fig. 2.2). Also, more than 29 GW of distributed solar were installed (more than half of it on homes) as of the end of 2019 according to the Solar Energy Industries Association.[27] These additions are much larger than what many expected only a few years back.

The influence of solar and wind on electricity markets and systems are already significant in some regions. Wind generation accounted for 7.2 percent of total U.S. generation in 2019, but reached 21 percent in ERCOT, which has nearly 29 GW of installed capacity and another 6 GW expected by the end of 2021. Utility-scale solar accounted for only 1.7 percent nationwide, but in California, about 14 percent of 2019 generation came from solar facilities. Including EIA estimates of small-scale solar (mostly as DER), the share of solar is about 2.6 percent.

Increasing wind and solar output has been eating into gas-fired generation's market share. This impact has been masked to a certain extent because CCGTs replaced most of the baseload generation lost to retirements. However, there is no guarantee that gas-fired generation will replace as much of the lost generation from future baseload capacity retirements given the expected large wind and solar expansion. That renewable energy will be able to replace baseload generation in larger scale is also supported by a couple of other trends. First, there is significant investment by the utilities in transmission grids across the country, partially to accommodate remote wind and solar resources. And, demands for larger investments to clear the hundreds of GWs of renewable capacity in interconnection queues are becoming louder. Second, many utility-scale solar projects are increasingly coupled with battery storage, which allows more of their generation to be supplied to the grid throughout the day.

Potential Potholes for Further Expansion of Renewable Energy
Still, renewable energy technologies face several challenges, which grow along with the scale and visibility of wind and solar facilities. **First**, despite the recent impressive record of expansion, the continued large-scale development of wind and solar capacity as well as the emergence of battery storage remains dependent on strong incentive mechanisms such as federal tax credits and state mandates. The expansion of tax credits by Congress in early 2016 led to a boom in wind and solar investment, particularly where state incentives or mandates supplemented federal tax credits. This wave has been much stronger than previous expansion periods because of lower cost and higher efficiency of wind and solar technologies. Encouraged by these trends, more cities and corporations are announcing renewable or clean energy targets, many as high as 100 percent within years (some by 2030), and are willing to sign long-term PPAs, which are essential for securing attractive financing. Batteries seem to be the next technology benefiting from a similar feedback loop.

Nevertheless, it is important to recognize that the plethora of incentives makes the wheels of clean energy investment turn. A good illustration of this dependence on incentives is the history of PTC. Every time Congress allowed PTC to expire, wind-capacity additions fell significantly the next year (Fig. 2.11). Despite cost declines of recent years, the history may repeat itself: capacity expansion is expected to fall after the PTC expires in 2020 based on planned projects. Some outlooks are more bullish but the average annual new builds are less than the average since 2016. Still, bullish outlooks are consistent with data reported earlier from Zummo (2020) and Berkeley Lab interconnection queue database.

If borne out in coming years, the decline in wind build-out suggests that wind costs are not expected to decline sufficiently to render wind competitive against alternatives across all geographies without federal tax credits. At least some customers who are willing to sign long-term PPAs

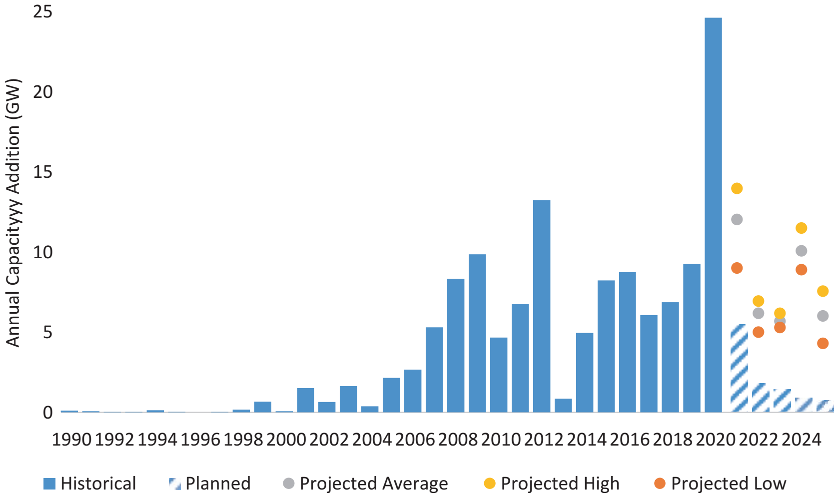

Fig. 2.11 Historical, planned, and projected U.S. wind-capacity additions. (Source: Historical and planned capacity additions are from the same EIA 860 data used in other figures in this chapter. 2020 data includes 18 GW that started operating in 2020 and another 6.5 GW that is expected online before the end of 2020. Projected figures are analyst projections as reported in Fig. 65 of Wiser and others 2020)

do so because of the attractive prices they receive. Prices are lower than a price that would allow for capital cost recovery with an acceptable rate of return to lenders and developers because tax credits allow them cash flow security, which facilitates financing with attractive terms. On the other hand, collectively, state, city, or corporate incentives may be adequate substitutes for PTC. It is also possible for Congress to extend PTC as part of the COVID stimulus package or separately.

We must also consider the global supply chains for wind and solar. The current level of renewables penetration would not have been achieved without the incentive mechanisms across the supply chain. Importantly, subsidies and mandates in the West encouraged China to invest in and subsidize solar panel manufacturing way beyond the country's own needs. About 40–45 percent of solar modules in the world are supplied by Chinese manufacturers. This still considerable market share is lower today owing to expanding manufacturing capabilities in North America, Japan, and elsewhere. Trade wars and the COVID pandemic demonstrated how supply chains can be disrupted. Recent resurgence of economic and political nationalism across the globe suggests further trade wars and disruptions to supply chains. A similar geopolitical threat is emerging for battery manufacturing. China is trying to control the supply of critical minerals and investing in Li-ion battery manufacturing although South Korean and a few Western companies are competing in the same space. The geopolitics of supply chains can push costs of solar panels, batteries, and windmills higher, which will likely necessitate the extension of government subsidies and incentive programs.

Regardless of how this complex geopolitical drama evolves, one observation stands: the demands of the renewables industry for continued policy support are contradicting the simultaneous claims that wind and solar are already competitive with conventional generation technologies based on levelized cost of electricity (LCOE) estimates. One reason for this incoherence is that generic LCOE estimates do not account for regional variations of the inputs of the LCOE formula, especially the capacity factor of wind and solar, which is determined by the quality of wind speed and solar irradiance and insolation of the location. But LCOE is also problematic for other reasons.

Second, wind and solar generation impose electricity system integration costs. These costs are not captured by generic LCOE estimates but electricity customers, taxpayers, and shareholders of mostly competing assets but also of renewable energy companies pay these system integration costs. See Gülen (2019) for a more detailed discussion with more references but most important of these costs can be summarized as follows:

- ***Intermittency:*** Wind and solar farms are not dispatchable by a system operator because the generation depends on availability of wind and sunshine. They get dispatched when resources are available. Resource adequacy necessitates real-time balancing and backup generation. Conventional thermal generation resources—mostly burning natural gas—provide these services. These plants must be compensated properly to remain available even if their annual generation declines. If the compensation is not adequate, some generation assets may become financially stranded.
- ***Variability:*** Wind and solar are also variable. Meteorological conditions (e.g., clouds and storms) and technical difficulties (e.g., equipment malfunction) can cause unpredictable variability in very short

time frames and increase system balancing needs. For example, at high wind speeds, operators shut down the turbines to prevent damaging them. A recent report by kWh Analytics[28] points out systemic underproduction by solar facilities due to optimistic irradiance assumptions, inadequate modeling that ignore intra-hour variability due to cloud cover, installation errors that lead to degraded cells and modules falling offline in first year of operation, and inverter failures. Such issues impact the ability of system operators to accurately predict wind and solar farms' generation in time frames ranging from minutes to hours and raise the cost of emergency balancing services.

- ***Cost of intermittency and variability:*** The literature estimates for balancing costs mostly range from \$1/MWh to \$5/MWh depending on the resource, penetration levels, and load profiles. Estimates for adequacy (i.e., backup) costs range from \$5/MWh to \$9/MWh for penetration levels less than 30 percent but can be as high as \$20/MWh at higher penetration levels.[29]
- ***Remoteness of best resources:*** One way to mitigate the intermittency and variability of wind and solar is to build them in best resource locations to maximize their capacity factor and their ability to complement each other[30] via expanding the transmission network. Utilities invested more than \$200 billion in new transmission capacity in the 2010s partially to facilitate renewables penetration (EIA 2018b). More T&D investment is required to accommodate growing utility-scale and distributed renewable energy capacity, much of which are waiting in the interconnection queue. Overall, the literature provides a wide range of \$2/MWh to \$22/MWh for grid costs, depending on the system characteristics and penetration levels.
- ***Overproduction:*** New transmission lines offer transitory relief. As more generation capacity is built in areas of high-quality resource, transmission capacity becomes insufficient and congestion costs rise again. Often, excess generation is curtailed. For example, in the early 2010s, new transmission lines were built to accommodate wind in West Texas. They reduced congestion costs for a few years. But, according to Potomac Economics (2020), congestion costs in ERCOT started to increase again in 2017. Constraints in moving wind-generated electricity out of wind areas is one of the main drivers and wind generation is increasingly curtailed. These costs and curtailment will continue to increase without new transmission capacity expansion. System operators in California and Germany

have also been curtailing renewable generation due to what Ueckerdt and others (2013) call overproduction. Wind generators in Texas bid negative prices to collect their PTC.[31] California pays Arizona to take its excess solar generation. Similarly, Germany sends its excess renewables generation to neighboring grids. Overproduction costs are negligible until the system achieves relatively high levels of penetration (e.g., roughly 25 percent for wind and 15 percent for solar in Germany, according to Ueckerdt et al. 2013). Overproduction costs increase at a fast pace after reaching these levels: $10–$20/MWh depending on the market for an additional 5-percent increase in share of generation.

- ***"Full-load hour reduction."*** As a result of subsidized renewables eating into their market share and lowering average prices, existing generators lose revenues.[32] During restructuring of regulated utilities, they were granted stranded cost recovery because utilities argued they made investments under the regulatory compact and restructuring to allow competition posed a threat to their cost recovery at allowed returns. Similarly, merchant generators made investments under the competitive-market construct, but renewables, and increasingly battery storage, are imposed on competitive markets by mandates and subsidies. Ueckerdt and others (2013) present "full-load hour reduction" costs that are akin to stranded costs and estimate them at $10–$20/MWh at 5- to 10-percent penetration of wind or solar.[33]

In short, as renewables penetration levels increase, these system integration costs become more visible. Notably, there is growing realization of the declining market value of wind and solar once their share of generation reaches a threshold, which is dependent on characteristics of each power system.[34] It is increasingly likely that, in order to recover their capital investment, wind and solar will become perpetually dependent on long-term PPAs, prices for which would have to increase[35] unless tax credits and mandates also continue.[36]

Some of the system integration costs are explicit in retail cost of electricity, which has been increasing across the Unites States despite historically low wholesale electricity prices. Increased T&D, renewables, energy efficiency, or other charges related with state clean energy programs add to customer bills. Barbose (2019) provides rough estimates of RPS compliance costs, which average 2.6 percent of retail electricity bills in 2018 with a range from 0.3 to 5.8 percent across states with RPS. This wide range is a reflection of differences of RPS programs across states but the higher shares are more likely in states that pursue wind or solar despite the poor quality of the resource in that state.[37] Importantly, Barbose (2019) omits the following costs: balancing costs ($1–10/MWh), T&D network upgrades ($2–20/MWh of costs versus $4–50/MWh of benefits), wholesale market price suppression ($30/MWh of consumer benefits that, as discussed earlier, becomes a stranded cost once generators are compensated for selling less power at lower prices or early retirement), and declining market value of renewables ($5–15/MWh for wind, $10–30/MWh for solar).[38]

However, RPS is not the only policy that matters. According to the Clean Energy Technology Center at the North Carolina State University, there are several thousand programs on supporting renewables, energy efficiency, battery deployment, and other clean energy applications across the United States.[39] A look at the average cost of electricity to end-users in comparison to average wholesale prices across many states depicts a picture of additional costs associated with all clean energy programs not just RPS. Perhaps the first observation from Fig. 2.12 is that residential costs of electricity[40] are much higher in California, New England, and New York. Also, residential costs diverged from wholesale prices faster, especially after around 2012 in first two regions.[41] Costs are expected to increase in these and other regions that pursue increasingly ambitious targets for not only established utility-scale wind and solar but also offshore wind, battery storage, electric vehicle (EV) charging infrastructure, and more technologies that will likely show up in customer bills as separate charges on increased T&D, renewable/clean energy, energy efficiency, and other programs.

The top row of states in Fig. 2.12 have an RPS or CES target of 50 percent or more by 2030. In the case of California, the striking divergence between the average cost of electricity to residential customers and the wholesale price of electricity is a reflection of the costs associated with roughly 150 programs California has in place in pursuit of its decarbonization goal.[42] Other states on the top row have been able to maintain residential costs relatively flat after 2010. There are many factors that determine the cost of electricity to consumers, including ratemaking approach followed by the regulators. But it seems safe to postulate that average residential cost of electricity remained flat in New Jersey and Maryland thanks to low price of natural gas from the Marcellus shale and

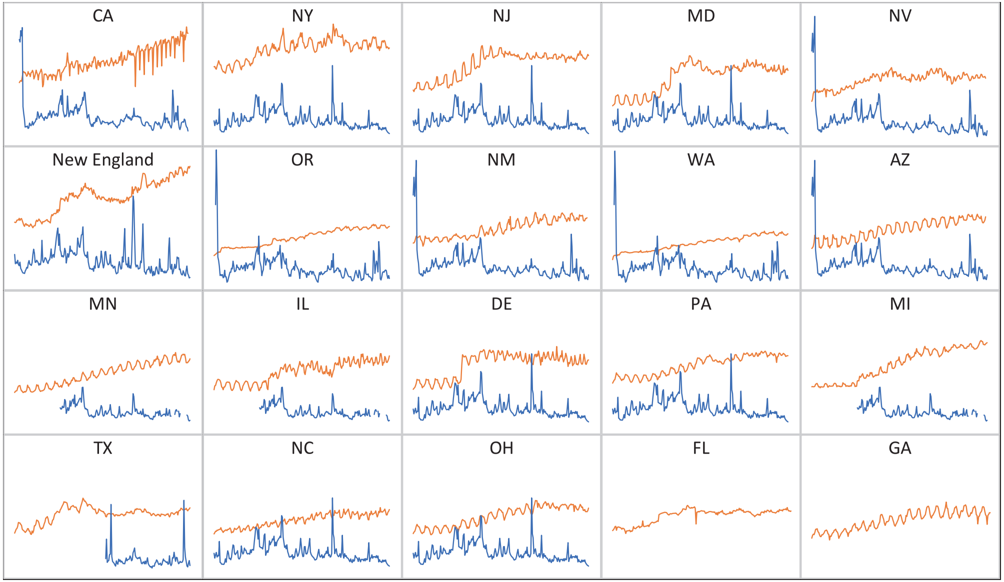

Fig. 2.12 Residential cost of electricity and wholesale electricity prices across the United States (January 2001–April 2020). (Average retail prices (costs) of electricity are from EIA Electric Power Monthly as reported in EIA's interactive data browser. Wholesale prices are from EIA's Wholesale Electricity and Natural Gas Data (https://www.eia.gov/electricity/wholesale/) except for Texas, for which I used average ERCOT energy price as reported by the independent market monitor, Potomac Economics. There is no wholesale market that is relevant to Florida and Georgia. For all other states, I used the wholesale price from the region closest to each state. In all charts, the left vertical axis is the average residential cost (orange line) with a maximum of ¢25 per kWh, and the right vertical axis is the wholesale electricity price (blue line) with a maximum of $300/MWh. States are grouped in rows relative to the RPS and/or CES targets. From first to last row, they represent: more than 50 percent by 2030; more than 50 percent by 2040–2050; more than 25 percent by 2025; and less than 12.5 percent)

the excess capacity resulting from compensation of generators from the generous PJM capacity market. Nevada's traditional utility regulation is probably the driver for relatively flat costs. New York continues to benefit from its nuclear plants and imports from the neighboring PJM market but still experiences significantly higher prices than PJM neighbors such as New Jersey, Maryland, and Pennsylvania.

The second row of states have an RPS or CES target of more than 50 percent by 2040 or later but before 2050.[43] In all five states, there is a sharp upward trend in residential cost of electricity. New England stands out: it is the only region on this row with a declining wholesale price in an organized market. New England states are pursuing high targets for wind and solar but also storage and energy efficiency. Altogether they have about 250 programs in support of clean energy. Programs are not well coordinated across states. Many states are actively blocking new natural gas infrastructure. Hence, the divergence between average residential cost of electricity and wholesale price has widened since 2013.

Oregon and Washington benefit from cheap generation from legacy hydroelectric assets. Coal and gas-fired generation dominates in New Mexico. Gas, coal, and nuclear have roughly equal shares (about 30 percent) in Arizona. Still, retail costs have been rising more than other states dominated by gas (e.g., PJM states, Texas, Florida, and Georgia). Wholesale prices in Oregon, Washington, New Mexico, and Arizona may reflect the large trade of electricity with California. In Karpa (2018), Clean Coalition—a nonprofit promoting DER—criticizes California's efforts to connect with neighboring regions for raising transmission costs in consumer bills. The main reason for these long-distance transmission lines is to import more renewables generation. Depending on how transmission costs are distributed across ratepayers in different states on the path of the transmission lines, customers in those states may also pay for some of the transmission costs.

The third row of states have RPS or CES targets of more than 25 percent by 2025. Although these targets are not as ambitious, some of these states are indicating bigger goals in the future. Also, pursuing solar in states with poor quality solar resource contribute to rising costs of electricity. Minnesota and Michigan fall into this category as do the New England states.

The last row of states either have low targets they have already achieved or do not have any targets. Texas stands out because of several factors. The competitive ERCOT market kept wholesale prices low thanks to several factors. Cheap natural gas produced in the state certainly played an important role but the state is also home to the largest installed wind capacity in the country, which has been expanding since the late 2000s. Retail choice also kept residential costs in check. All states on this row experienced somewhat rising electricity costs in the 2000s which stabilized in the 2010s thanks to mostly large gas-fired capacity expansion and the low cost of natural gas. All had average residential costs below the U.S. average in the 2010s.

Finally, renewables too have environmental and geopolitical impacts. A fundamental challenge is their large footprint given the low capacity of individual units (windmills or solar panels) and low capacity factor. As renewables scale up to capacity levels that are necessary to replace conventional generation technologies, environmental impacts are becoming more visible such as clear-cutting of forests or damage to desert ecology. The most notorious example of local opposition to a renewables project is probably the Cape Wind offshore wind farm that, after 16 years, was cancelled because of opposition from "wealthy property owners like the Kennedys, Mr. Koch, and Rachel Lambert Mellon" and economic concerns of many local officials, businesses, residents, Indian tribes, and environmental activists due to high cost of offshore wind power or impact on the local environment (e.g., Seelye 2017).

However, similar groups, mostly local but also some national environmental NGOs, objected to solar farms in Joshua Tree National Park and Mojave National Preserve, offshore wind farms along the Texas Gulf Coast, wind or solar facilities in New York City, and many more. Transmission projects are also blocked. For example, New Hampshire blocked a high-voltage line from Québec to bring hydroelectricity to Massachusetts. Environmental justice activism that has been successful in re-routing or forcing cancellation of fossil fuel projects such as pipelines, storage facilities, or LNG terminals is also looking into siting of large-scale renewable energy projects to prevent unfair treatment of disadvantaged communities. Increasingly, recycling of solar panels, batteries, and windmills that reach the end of their useful life or break down is attracting attention because they contain toxic minerals. As larger capacities get old, the renewables industry and its observers are realizing that recycling has to scale up and be done in a responsible manner. Otherwise, public backlash is guaranteed.

Finally, the supply chain of minerals necessary for manufacturing of clean energy technologies is global. As such, environmental and social impacts associated with minerals mining, processing, and transportation as well as manufacturing and shipping of various pieces of equipment multiply as demand for these technologies grows. Also, geopolitical and economic competition for resources that is already evident will increase. O'Sullivan and others (2017) call this emerging dependence on minerals for clean energy technologies the "new" resource curse.

In short, these three challenges will grow in significance as footprints of clean energy technologies increase. Nevertheless, it is unclear whether opposition to renewables will ever reach the same high pitch as refusal of fossil fuel infrastructure. A lot will depend on each industry's ability to find and successfully implement publicly acceptable solutions to their externalities.

Harmonization of Natural Gas and Power Systems

In systems with increasing share of intermittent and variable resources that are being better connected across larger geographies via expansion of transmission networks, gas-fired plants are needed less for baseload generation and more for balancing and resource adequacy. Even those roles are challenged as some regions seek alternatives such as battery storage to provide these backup services.

These shifts in utilization of gas-fired plants raise some issues regarding the co-optimization of natural gas and electric-power infrastructure and markets that function on different time scales and economic parameters. For example, increased cyclical use of gas-fired plants has implications for pipeline deliverability of gas. Changes in how much gas is required where, when, and at what pressure force changes to utilization of natural gas infrastructure. Reserving capacity in pipelines may have to change into shorter time periods (e.g., measured in hours) and may have to be done in very short notice or none at all. Storage needs will likely increase and diversify, perhaps necessitating the use of unused capacity of pipelines as storage (linepack). Since pipeline throughput is likely to go down in a power system with more variable resources, room for linepack should be larger. But, such utilization will likely increase the wear and tear on equipment adding to the cost of maintenance. FERC and the North American Energy Standards Board have been working on these issues since the early 2010s but gas–power harmonization remains a challenge.

Disruptive Technologies

Many technologies—especially consumer technologies—have been altering the electric-power landscape and fueling visions of micro grids, smart grids, and VPPs. Indeed, demand-side technologies such as rooftop solar, programmable thermostats, remote-controlled appliances, and others have the potential to empower consumers into prosumers. The emergence of this power ecosystem is certainly posing risks for central generators as well as utilities but it will take some time for large-scale impact to be visible and it is too complex to cover here. Instead, I will focus on battery storage because it is one technology that is promoted heavily to mitigate problems associated with intermittency and variability of wind and solar and is also integral to future visions of mini grids and VPPs.

The Berkeley Lab interconnection database included 48 GW standalone battery storage in queue in addition to 97 GW solar with battery storage and 9 GW wind with battery storage. California accounts for 15.5 GW of battery storage, 17 GW of solar-storage, and 5 GW of wind-storage projects. According to the EIA data, nearly 4 GW of storage are expected between 2020 and end of 2023. In contrast, CTs built since 2000 have net summer capacity of nearly 89 GW. The total gas fleet capacity is more than 500 GW.

However, batteries remain expensive and pose technological challenges, such as depletion of capacity and deterioration of charge–discharge cycles, that reduce their value to the grid. Even the solar–storage combination is more expensive than other alternatives without ITC and state support of solar facilities. Lazard (2019b) reports a levelized cost range of $165/MWh to $325/MWh for in-front-of-the-meter storage, which declines to $102–$139/MWh when combined with solar PV. Standalone storage used by T&D utilities or commercial and industrial facilities are more expensive, often costing more than $1000/MWh. In contrast, an existing CT can supply electricity at less than $100/MWh, even at $5/MMBtu natural gas and 10-percent capacity factor. The average cost of gas peaking since 2016 (2008) from Fig. 2.7 is $46 ($61) per MWh.

Forecasts of EV demand are more bullish than grid-scale battery-storage forecasts. Rapid growth of lithium-ion battery demand for grid-scale storage and EVs will have repercussions on minerals markets. We have already seen lithium and cobalt prices triple between 2015 and 2018. Unsurprisingly, these price signals induced new investment in mining, processing, and transportation capacity, thus reducing prices. As natural resources in increasing but variable demand, it is reasonable to expect this volatility to be a permanent future of these markets just as they have been for other natural resources. The cost of minerals is usually a small part of the cost of a battery but disruption of access to these minerals critical to battery manufacturing and performance can have implications along the supply chain.

Researchers assert new battery chemistries will be needed not only to eliminate geopolitically or environmentally undesirable minerals such as cobalt, but also to reduce battery degradation, to store more power, to extend discharge time at rated power, and to improve safety.[44] Byrne and others (2018) highlight the need for regulatory consistency to develop energy management systems and optimization tools that can accommodate different technologies serving different energy and power functions. Similarly, Sivaram (2018) argues the current solar PV technology based on silicon is not sufficient for solar to claim a much bigger share of the energy space; he states the industry must invest in "technological innovation to harness the sun's energy more cheaply and store it to use around the clock," and "redesign systems like the power grid to handle the surges and slumps of solar energy."

These and other challenges have the potential to curtail smooth expansion of batteries. Nevertheless, batteries and other emerging technologies will continue to complement already established wind and solar to disrupt the traditional power systems. For example, Dyson and others (2018) argue "the current rush to gas in the U.S. electricity system could lock in $1 trillion of cost through 2030…clean energy portfolios are cost-competitive…" The portfolios are based on an IRP approach and consist of energy efficiency, demand response, battery storage, and distributed and utility-scale renewables. I find some of their assumptions unrealistic. For example, they assume a natural gas price higher than the most recent EIA outlooks in Fig. 2.9; and assume away difficulties faced by cross-jurisdictional transmission lines (e.g., see Walton 2018). In Trabish (2018), the head of Integrated Innovation and Modernization at Southern California Edison, which pursues a DER-heavy strategy and looks at storage to replace gas peakers, calls the scale and scope of portfolios and changes necessary to achieve them "unprecedented."

Nevertheless, it is possible to see IRPs around the country that mimic portfolios from such studies. Their influence is strengthened by industry developments such as the Aliso Canyon natural gas–storage leak and pipeline explosions (especially those near population centers). Following the Aliso Canyon leak, California has more aggressively pursued battery storage as an alternative to natural gas peakers. Seven states already have targets for energy storage deployment and New England is pursuing a clean peak standard. More states are expected to follow their lead. FERC issued Orders 841 and 845 to remove barriers to storage's participation in energy, capacity, and ancillary-services markets. Some jurisdictions, such as Arizona, have placed a moratorium on new gas builds until alternatives such as solar-storage combinations are explored. Many customers demand storage to be added to their solar farms (hence the 97 GW in interconnection queue). PPAs for solar-storage projects have been priced as low as $36/MWh at the time of writing. In short, despite its challenges, battery storage will have significant impact in certain regions.

Social License to Operate

Gas-fired generation has a large advantage over coal with respect to local emissions and land impact (e.g., coal ash disposal) but also with respect to carbon dioxide (CO_2).[45] The FUTURE Act, included within the Bipartisan Budget Act of 2018, increased the tax credit "incrementally over ten years from $10 to $35 per ton of CO_2 stored geologically through enhanced oil recovery and from $20 to $50 per ton for saline and other forms of geologic storage" and may help some coal-fired plants, especially if the cost of CCS also improves. Although accepted as necessary to combat climate change by many energy experts, CCS does not seem to have much public support.

The CPP was stillborn but a growing number of states and cities are pursuing decarbonization policies to comply with the Paris Agreement on climate change. The public perception of what clean technology penetration can achieve influences these policies and difficulty of securing social license to operate for natural gas infrastructure. Efforts to block gas infrastructure—including power plants and ways of delivering gas to power plants, such as pipelines and upstream operations—act as proxies to a CO_2 tax and may increase the cost of natural gas, especially if the price-suppressing effect of associated gas supplies recedes. Adding to the challenges of the natural gas industry operations are the resolutions by cities around the country to ban gas connections in new homes. Whether these relatively few cases will turn into a trend is uncertain but it is yet another component of a growing anti-gas movement. In some regions, it is certainly part of a long-term goal. For example, Massachusetts Attorney General followed on the examples of New York and California and called for an investigation of the gas sector to ensure "safe, reliable and fair transition away from reliance on natural gas and other fossil fuels" (see reporting in Walton 2020).

As discussed in "Weaknesses" and "Threats" sections, financial institutions and management consultancies are also putting pressure on companies to decarbonize. Some of these pronouncements may not have much teeth, at least not yet, but they certainly contribute to public discourse against fossil fuels. If standard reporting of environmental impacts or simply GHG emissions or exposure of assets and operations to climate risks becomes a requirement by governments, investors may have to scrutinize fossil fuel companies and projects more closely.

These developments influence federal regulation as well. Although its centrality ebbs and flows with the changing mix of commissioners, FERC commissioners debate whether to consider climate impacts of new natural gas infrastructure up the supply chain while evaluating midstream and downstream projects. Methane emissions along the supply infrastructure and flaring at the wellhead are two visible challenges the oil and gas industry must mitigate in order to counter growing opposition to the cleanest burning fossil fuel. In the meantime, communication of massive benefits of natural gas in reducing local pollution when it replaces coal should continue.

Conclusions

The power sector is primed to burn more natural gas. Nearly half of installed capacity in the United States will be fired by natural gas and the capacity-weighted average age of the CCGT fleet will be less than 20 years by the mid-2020s. With more coal and some nuclear plants slated to retire, more gas burn for power generation seems certain, at least in the early 2020s. Predictably, new gas-fired capacity has been expanding the most in regions with most baseload capacity retirements such as the PJM, Midwest, ERCOT, and Southeast region. All of these regions also happen to be either home or in close proximity to shale plays with relatively easy access to low-cost gas. However, there are headwinds even in these regions.

Decarbonization policies are spreading across the country, promoting renewables, both utility-scale and distributed, as well as demand-side measures to increase efficiency, conservation, and demand response. These efforts build on the momentum gained since the 2008 Great Recession with the help of a large set of support policies at federal, state, and local levels. At the same time, a growing anti-gas movement raises questions about the financial and physical health of the natural gas industry and infrastructure, which is reaching the age of replacement in certain parts of the country.

Consumers and regulators are increasingly aware of system integration costs, many of which are reflected in higher customer energy bills, associated with the penetration of intermittent and variable resources. But lower costs and rising concerns about climate change sustain the momentum behind decarbonization efforts. More wind, solar, and energy storage but also geothermal and biomass will certainly be added in the future and will continue to take market share away from gas-fired generators.

The argument that gas-fired generation is the perfect complement to intermittent and variable wind and solar generation is problematic. Although technically accurate, shifting gas-fired plant use away from baseload to balancing and backup will burn less gas as the share of renewable energy increases. A better integrated grid and storage will reduce the need for load-following units further. Even baseload generation will be lost to wind and solar. After all, eliminating fossil fuel-based generation is a goal of energy transition. This gradual shift in utilization of the gas fleet will require proper compensation of units forced to cycle more. However, reforms of organized markets to fix compensation schemes have been contentious. While there is policy and public support for wind, solar, and nuclear, which lays the ground for out-of-market compensation of those generators, natural gas is taken for granted as the "bridge" fuel. The "length and width" of the bridge is a policy risk to financial sustainability of even newer CCGTs. Building too much gas-fired capacity in certain markets adds to the risk of cash flow security for all generators in that market. Regions where utilities pursue IRPs with the approval of regulators offer a more predictable yet still changeable future for utilization of gas-fired plants.

This complex set of drivers for gas burn are captured in four dimensions of Fig. 2.4 and discussed in some detail throughout the chapter. This discussion can be summarized in Fig. 2.13 that demonstrates the wide range of uncertainty around gas-fired generation over the next 15 years. The wide range results from the balancing of four dimensions' possible movements in pushing gas burn higher or lower. I distinguish between the near future (roughly through 2025) and the more uncertain long-term (beyond 2030). I provide AEO 2020 low and high envelopes for comparison purposes. Importantly, I assume flat load, mimicking the 2010s. If substantial

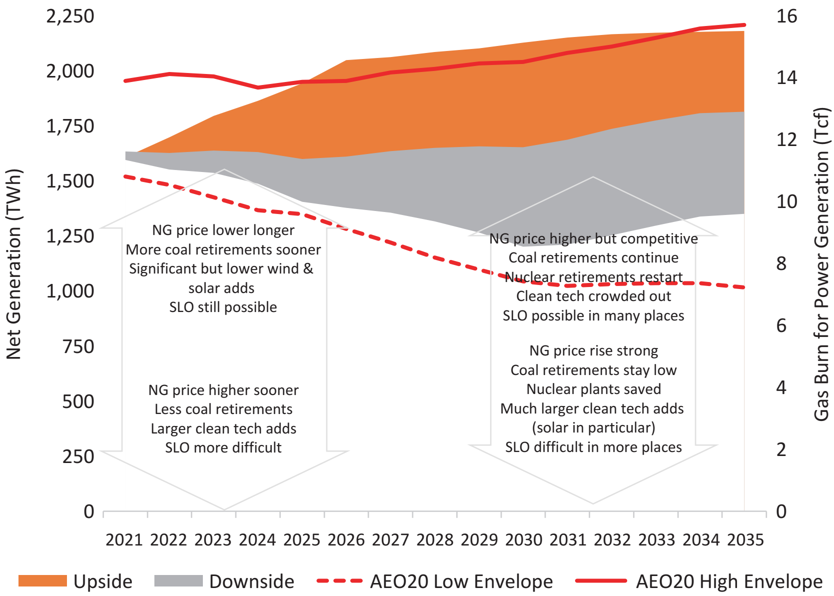

Fig. 2.13 Wide range of the future gas-fired power generation. (Source: Author estimates. EIA AEO 2020 envelopes capture lowest and highest gas-fired generation for each year across all AEO 2020 scenarios)

load growth occurs, say due to rapid electrification, gas burn should benefit from it within the time frame of this analysis.

The existence of a young, efficient, and dispatchable gas fleet along with relatively abundant cheap natural gas provides an advantage to gas-fired generation to replace retiring baseload capacity. Coal and nuclear fleets are aging. Large-scale retirements of coal-fired capacity should continue through the 2030s in an environment of low electricity prices. Subsidized CCS may save a handful of coal-fired capacity but not the great majority of old coal plants with declining utilization. Nuclear plants are being saved by state initiatives mainly due to their zero-emission attribute and local economic benefits. However, by the 2030s, states may not be as inclined to save plants with expiring 60-year licenses.

A regional bifurcation must be recognized. Roughly speaking, baseload coal and nuclear retirements occur in regions where gas resource is available, renewable resource quality is weak, and cost of electricity to end-users is an important political consideration. These conditions help natural gas. But other regions of the country, without ready access to low-cost gas but with better wind and solar resources, will double down on their decarbonization targets. This divergence is important to track, in particular for the fate of existing and for the purposes of siting new midstream infrastructure. A gas-fired plant is valuable only if it has access to reliable supply of natural gas.

This regional divergence is not unqualified. Even the former regions are home to many states pursuing energy transition despite the availability of low-cost gas. To the extent the transition proves successful in terms of reliability, affordability, and acceptability, it can spread to other states. The success, however, is contingent upon continued policy support in the form of tax credits, mandates, and other measures at federal, state, and local governments for investment in renewable generation, storage, and T&D enhancement. Such support appears set to grow in many regions building on the momentum gained in the 2010s but the size and scope of it is dependent on federal and regional politics that will have to balance the pros and cons of the dimensions discussed in this chapter.

Notes

1. Halfway through 2020, gas-fired generation continues to grow year-on-year at the expense of coal-fired plants, signaling more coal retirements.
2. Throughout this chapter, the United States refer to continental 48 states, excluding Alaska and Hawaii.
3. Secondary to this deregulation of the natural gas market, years of DOE funding to hydraulic fracturing and horizontal drilling research, Nonconventional Fuels (Section 29) Tax Credit that went into effect in 1980 and other programs helped the eventual development of low-permeability resources in the late 2000s.
4. These nameplate capacities are not one-to-one comparisons due to intermittency of wind and solar. When adjusted wind summer peak availability, which is, for example, 14 percent for noncoastal wind and 58 percent for coastal wind in Texas, dispatchable gas-fired capacity is much higher than available wind capacity. Solar peak availability is much higher (e.g., 77 percent in Texas), but accounting for it would still widen the gap between gas and solar capacities.
5. For example, offshore wind projects along the northeastern seaboard are getting mandated by states while states in Southwest pursue stronger solar and solar-storage mandates.

6. Based on Berkeley Lab Electricity Markets & Policy Group database: https://emp.lbl.gov/generation-storage-and-hybrid-capacity
7. Some of the retired coal-fired capacity was replaced with CCGT plants in the same location (roughly one-fifth). In roughly equal amount of capacity, boilers were converted to burning natural gas. In this chapter, I simply refer to all of these options of stopping coal burn as retirements of coal-fired capacity.
8. There are many issues with competitive electricity market designs, which vary across regions and over time. I will highlight some of the issues with direct impact on gas burn later in this chapter but interested readers can find a more in-depth discussion of key market design issues in Gülen (2019).
9. There is an emerging view among economists and other social scientists that rejects neoclassical economics that sees labor as a cost. This socioeconomic context is fully woven into the fabric of public support for energy transition. These trends induce growing bipartisan support for bringing local manufacturing and jobs back.
10. For example, Energy Intelligence developed a Vulnerability Index to assess "which oil and gas companies are best placed to survive the energy transition."
11. For example, Task Force on Climate-related Financial Disclosures is developing standards for reporting climate-related financial risk exposure to investors, insurers, and other stakeholders. The Partnership for Carbon Accounting Financials lists 69 institutions with financial assets estimated to be worth $9.7 trillion (as of July 31, 2020). Most are non-U.S. institutions and many are small, but the list is growing and includes Citi, Bank of America, and Morgan Stanley.
12. NC Clean Energy Technology Center has been maintaining a database of these programs: https://www.dsireusa.org/
13. For example, a carbon tax will increase the natural gas price whereas banning new gas connections in certain regions has an indirect, if any, effect on the natural gas price across the country.
14. We used a commercial software also used by utilities, merchant generators, and system operators. Every user can adjust the database of existing fleet of generators, their operational characteristics, planned additions and retirements, and so on. The model's algorithm is a good reflection of how power systems operate to meet demand and supply reliably in real time (known as security-constrained economic dispatch and unit commitment). The model also does a good job of estimating least-cost expansion of generation capacity to meet the needs of any demand outlook.
15. Roughly speaking, 1 Tcf is equivalent to an average of 2.7 billion cubic feet per day, or Bcf/d.

16. Ideally, a dispatch model is required to assess the contribution of each type of generation in each power system.
17. In fact, plants announced to be retired, especially coal-fired, may already be generating below the average capacity factors.
18. According to the NC Clean Energy Technology Center, as of July 2020, California has 148 programs across city, utility, state levels that cover rebates, grants, building energy codes, permitting standards, tax incentives, and other mechanisms to promote clean energy projects (https://www.dsireusa.org/).
19. See Gülen (2019) for a detailed discussion of electricity market uncertainties that dominated the 2010s. Market designs continue to evolve with attendant risks to power sector participants.
20. Wind generation in ERCOT peaks in the spring (often March or April). In addition to switching due to relative competitiveness of coal and gas generators, their share is also impacted in the shorter term by seasonal availability of wind.
21. Natural gas prices in the Marcellus region suffered from significant basis differential due to increased production stranded without sufficient pipeline capacity.
22. Mcfe rather than MMBtu is used because this metric captures the value of not only methane but also other molecules produced at the wellhead. If production is dry gas (i.e., almost all methane), Mcfe and MMBtu prices will be roughly the same.
23. Many analysts have published forward natural gas price decks approaching $3/MMBtu during 2021 with some suggesting $3.50 or higher. Most of these views hinge on the reduction in associated gas yield with lower oil output as softer prices for crude oil discourage drilling in oilier plays, as explained in Chap. 1.
24. See Gülen (2019) for a detailed discussion of some of these design changes.
25. According to North American Electric Reliability Corporation (2020).
26. In contrast, average capacity factor for the U.S. coal fleet has been declining and reached 47 percent in 2019. As a result, CCGTs will have to increase their utilization more for every GW of nuclear capacity retired as compared to coal-fired capacity retirements.
27. Note that the installed capacity of distributed solar is reported in direct current (dc) by the SEIA and not as net summer capacity as reported by the EIA for utility-scale solar. As such, 29 GWdc is not readily comparable to other capacity figures in this chapter.
28. 2020 Solar Risk Assessment: https://www.kwhanalytics.com/solar-risk-assessment (accessed July 28, 2020).
29. Estimates are mostly from Heptonstall and others (2017) and Ueckerdt and others (2013).

30. Generally speaking, wind is available in early mornings and evenings while solar reaches its maximum during midday to late afternoon.
31. Tsai and Eryılmaz (2018) find in ERCOT, "for every additional 1000 MW of wind generation in a Real-Time 15-minute Settlement Interval, nodal prices at non-wind resources would be suppressed by $1.45/MWh to $4.45/MWh, with considerable heterogeneity across time and space."
32. For example, Tsai and Gülen (2017b) show that in ERCOT, high wind penetration correlates with gas-fired units (CCGTs as well as CTs) cycling more as well as ending up with lower capacity factors and revenues.
33. Incidentally, the state incentives to nuclear plants have been in the same range.
34. For example, Sivaram and Kann (2016) report that when solar reaches 15 percent of generation in a system, its value falls by more than one-half. See Gülen (2019) for additional references.
35. As quoted in Penrod (2020), a VP at LevelTen, developer of PPA Price Index, sees prices leveling off or possibly increasing driven by expiring tax credits, supply chain bottlenecks, and other factors. These increases reduce renewables' competitiveness but are not irreversible with more economies of scale and technological advances in the future. Still, they highlight the irrationality of expecting recent pace of cost declines to continue.
36. An alternative is a return to integrated resource planning (IRP) where generation portfolios are determined by regulators and utilities. Gülen (2019) provides an outline of a competitive IRP construct.
37. Page 43 of Barbose (2019) lists six studies published between 2013 and 2019, all of which report from low single digits to up to 17 percent of rate increases, with increases higher than 10 percent seen in states with most aggressive RPS policies.
38. See page 39 of Barbose (2019), which also lists some benefits. Note, however, that most benefits are conceptual (e.g., global benefits of reduced carbon emissions) whereas most costs find their way to electricity bills. Also note that cost estimates reported in parentheses are consistent with literature ranges provided earlier.
39. For details, visit http://www.dsireusa.org/
40. EIA calculates this cost by dividing the electricity providers' operating revenues by sales of electricity to different customer classes. Revenues include energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, other miscellaneous charges, and taxes (state, federal, other).
41. For example, according to Barbose (2019), the share of RPS compliance costs increased from less than 8 percent in 2016 to almost 12 percent in 2018 in Massachusetts.

42. See Griffiths and others (2018) for an attempt to quantify costs of some California clean energy programs.
43. The regulatory staff in Arizona proposed a 100-percent CES by 2050 in July 2020.
44. For example, American Chemical Society publication, *Chemical Reviews*, dedicated a full issue to the topic of "Beyond Li-ion Battery Chemistry": https://pubs.acs.org/toc/chreay/120/14
45. Following common practice, I use carbon dioxide to represent all greenhouse gases, which also include methane, nitrous oxide, and fluorinated gases. All tons are metric tons.

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