U.S. POWER INDUSTRY OUTLOOK 2019

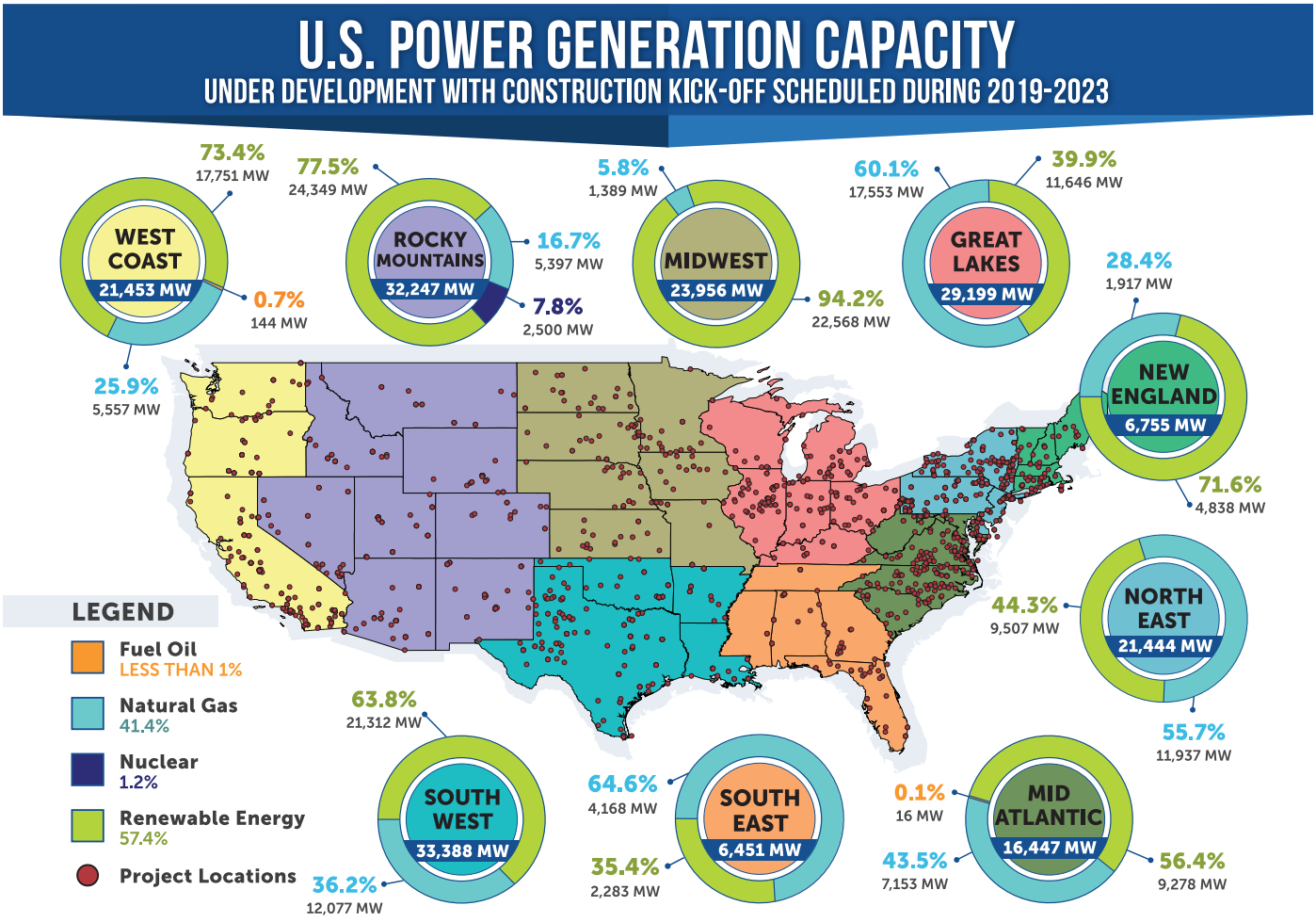
YEAR TWO OF THE TRUMP ADMINISTRATION SAW WIDESPREAD INTERVENTION IN ENERGY MARKETS

BY BRITT BURT & BROCK RAMEY

President Donald Trump's plan to transform the domestic energy market took several steps forward in 2018, most notably the releasing of the Affordable Clean Energy rule in August. The Trump administration's initiative largely delegated to the states decisions about regulating carbon dioxide emissions from coal-fired power plants. Andrew Wheeler, a former coal-industry lobbyist, took over as the U.S. Environmental Protection Agency's (EPA) acting administrator last July.

The intended beneficiaries of the administration's regulatory rollback are oil & gas companies, coal firms, coal-burning electric utilities, and electric utilities that own nuclear power plants.

The administration's efforts drew support from the nuclear and coal industries but criticism from state, regional and federal regulators, along with sectors of the energy market that could lose if the subsidies go through, including renewable energy companies, oil & gas producers, merchant generators, gas power interests, and industrial energy users.



Industrial Info Resources

All data derived from Industrial Info's Database (August 2018)

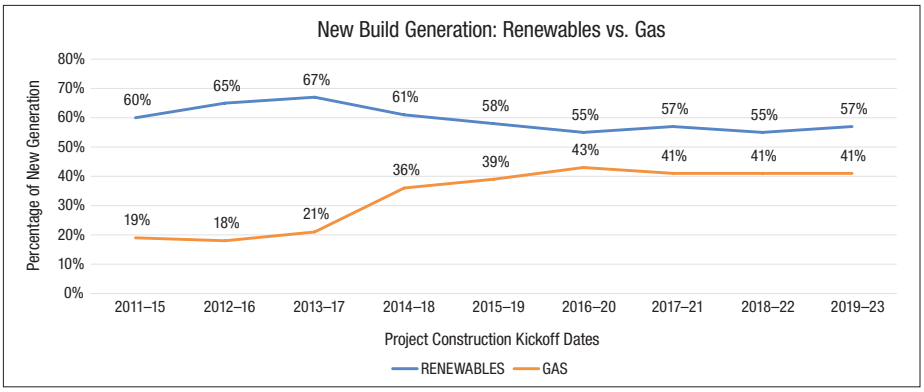


Figure 1: Renewables' and gas' share of the new-build generation market over the last nine five-year periods. *Source: IIR*

By and large, coal-burning utilities have not changed their plans to continue reducing their reliance on coal-fired generation in favor of gas or renewable generation. As of the time of writing, no company had announced plans to develop a new coal-fired power plant in the U.S. during 2018. Many analysts doubt a coal-fired generator will be built in the U.S. over the next five years.

Some measures enacted this year, including the imposition of stiff import tariffs on steel, aluminum and solar cells and panels, were not welcomed by power generators or other segments of the energy industry. They may drive up costs and disrupt the economics of near-term projects.

The President and his aides said the tariffs amounted to "short-term pain for long-term gain." There was some early indication that was true, at least for steelmakers. Profitability returned to the steel industry. Several steelmakers expanded output, capital expenditures, and employment in response to the president's moves.

But those measures also triggered a tit-for-tat, dollar-for-dollar retaliation from countries that export goods to the U.S. A potentially devastating game of "tariff chicken" has begun with each side vowing to protect their interests via successive rounds of tariffs and restrictions. Aside from increasing input costs to electricity companies, which use steel in constructing new assets, it is not clear how all of this could end.

Outside of Washington, D.C., the U.S. power generation market continued to be a two-fuel game: renewable energy and natural gas. According to data tracked by Industrial Info Resources (IIR), renewable energy will account for about 57.4% of all power generation projects scheduled to begin construction between January 2019 and December 2023. That amounts to about 121,532 MW of new generation capacity.

Natural gas, by contrast, is expected to account for approximately 87,647 MW of new generation to be built in the U.S. over the next five years, about 41.4% of all new-build generation.

Renewables' share of the new-build market has slipped a bit from its pinnacle of 67% during the 2013–2017 period (Figure 1). Some of that lost market share was captured by natural gas, as the "dash to gas" mantra helped to more than double gas' share of the new-build market over the last decade. But most of gas' gains came at the expense of coal-fired and nuclear power, which had brighter five-year outlooks a decade ago.

During the height of the "nuclear renaissance," nuclear power was scheduled to account for about 13% of all new generation built over the 2011–2015 and 2012–2016 periods, according to IIR. Today, cost overruns and construction delays have soured utilities, investors, regulators and customers on new-build nuclear power.

Only one grassroot nuclear generation project is scheduled to kick off over the next five years: the long-delayed Blue Castle Nuclear Plant in Green River, Utah. New-build nuclear is expected to account for slightly more than 1% of all generation capacity to be built over the 2019–2023 period.

Coal outlook

Despite proclamations that the war on coal is over, there is little evidence to date that coal mining or coal-fired power has turned a corner or will do so in the near future. Indeed, the U.S. Energy Information Administration reported that the amount of coal used by power generators in the U.S. fell to three-decade lows, about 661 million short tons in 2017, down about 36% from its 1983 peak.

In the U.S., the percentage of electricity generated from coal is expected to fall to 28% in 2018 and 27% in 2019, down from 30% in 2017. An expected uptick in exports will not be enough to overcome continued reduction in domestic thermal coal use.

Overall coal production will decline about 1% in 2018 and 2% in 2019, the Energy Information Administration (EIA) projected in its August 2018 Short-Term Energy Outlook.

Coal-mining companies employ about 53,000 people, according to an August 2018 estimate from the Federal Reserve Bank of St. Louis (Figure 2). That figure, which represents all job classifications in the industry (not just coal miners), was up slightly from 2016, but down dramatically from previous years. Coal interests have said recent coal initiatives have slowed the bleeding and pro-

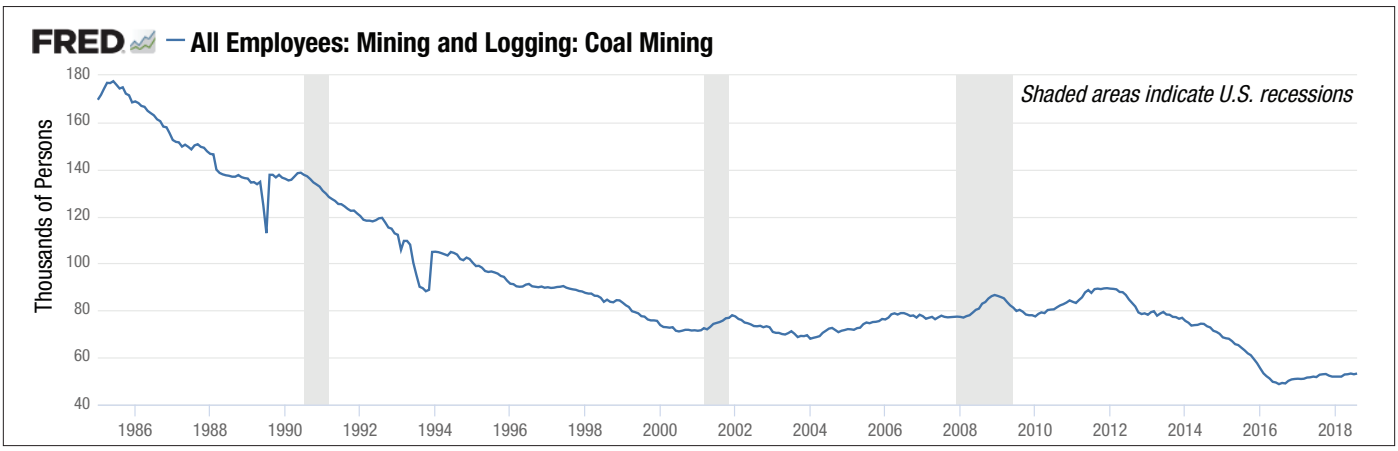


Figure 2: U.S. coal company employment since 1986. *Source: Federal Reserve Bank of St. Louis (FRED)*

Construction work for environmental remediation at some coal plants may be pushed back

vided an opportunity to rebuild.

Power generators closed more than 12,000 MW of coal-fired capacity in 2018. Closures are expected to continue over the next five years. Although asset owners closed less coal generation in 2018 than in past years, that shuttered capacity is not being replaced by new coal-fired generation. Typically, some combination of gas-fired generation, renewables, storage and customer-facing energy efficiency programs is being used to replace the lost coal generation.

No new coal-fired generation is scheduled to be built between 2019 and 2023. In fact, asset owners have cancelled or postponed the start of construction for 40 coal-power projects valued at about $11 billion that were scheduled to begin construction during that five-year period.

New generation accounts for about $7 billion of cancelled or delayed projects, while pollution-control and carbon-recovery projects account for more than $2 billion of planned projects that have been abandoned or pushed back.

Navajo Generating Station (NGS), the largest coal-fired plant west of the Mississippi River in northern Arizona, plans to close its three-unit, 2,250-MW coal-fired plant by the end of 2019.

In Ohio, Dayton Power & Light Company (DP&L) closed two coal-fired plants with a combined generating capacity of 2,373 MW during the summer of 2018. The affected plants are the J.M. Stuart Station (1,755 MW) and the Killen Station (618 MW).

Evergy, the Kansas utility holding company formed by the merger of Great Plains Energy and Westar Energy, announced plans to close about 805 MW of coal-fired generation by yearend 2018.

At the end of last summer, FirstEnergy's merchant unit announced plans to close three coal-fired plants totaling over 4,000 MW of generating capacity. The plants were units 1–3 of the Bruce Mansfield plant in Pennsylvania, and units 5-7 of the W.H. Sammis plant in Ohio. The plants would close in 2021 and 2022.

"As with (our) nuclear (plants), our fossil-fueled plants face the insurmountable challenge of a market that does not sufficiently value their contribution to the security and flexibility of our power system," said Don Moul, president of FirstEnergy Solutions Generation. "The market fails to recognize, for example, the on-site fuel storage capability of coal, which increases the resilience of the grid."

Aside from those closures, owners of coal-fired generators in Maryland, Mississippi, Florida, Iowa, Michigan, Wisconsin and Texas all announced plant closures in 2018.

IIR tracks about 70 capital projects valued at about $3.4 billion scheduled to begin construction at U.S. coal-burning power plants between January 2019 and December 2023. Most are for environmental remediation, including installing equipment to limit NOx emissions and complying with regulations like Coal Combustion Residuals (CCR) and Effluent Limitations Guidelines (ELG).

But there is a chance that some of that scheduled work will be pushed back following a mid-2018 revision to the CCR regulation from the EPA delaying the effective date of some coal-ash pond clo-

sures and granting more flexibility to states and utilities in how they treat those sites.

That first set of revisions to the CCR rule will affect an estimated 400 coal-fired power plants across the country. The EPA estimates the new rules will save power plant owners $28 million to $31 million annually on compliance costs.

The first set of revisions to the CCR rule was the first major policy decision of Acting Administrator Andrew Wheeler. A second set of revisions to the CCR regulation, expected to be issued in early 2019, is likely to address how to recycle coal ash to make concrete, gypsum wallboard and pavement. IIR is tracking two dozen CCR-related projects valued at about $1.75 billion.

The EPA is expected to make changes to another regulation affecting coal-fired generators, the Effluent Limitations Guideline (ELG) rule. Five ELG projects valued at about $282 million are scheduled to kick off at coal-fired power plants over the 2019-2023 period.

Another type of construction activity at coal-fired generators — plant decommissioning and demolition — is expected to generate about $343 million of work over the next five years. Additionally, in-plant capital outlays to refurbish boilers and rewind, replace or upgrade turbines is expected to account for about $151 million of work over the next five years.

Natural gas outlook

Gas is great
Gas is good
What could stop it?
Regulators could!

Though that ditty was not heard at recent industry conferences, it became increasingly apparent in 2018 that state regulators could do what geology or economics could not: slow the rise of new-build, gas-fired generation.

As is often the case, it appears California started the trend. Under separate mandates from the state legislature to reduce carbon emissions and increase the use of renewables, the state's utility regulators began turning against gas-fired generation in 2018.

One data point in this trend was the decision by the California Public Utilities Commission (CPUC) in January 2018 to deny Pacific Gas & Electric (PG&E) the opportunity to use power from three existing gas-fired units to meet customer demand and system voltage requirements. Those three Northern California plants, totaling about 700 MW of generation capacity, are operated by Calpine Corporation.

Another data point is a 564 MW, out-of-market gas-fired power plant in San Jose. Also owned by Calpine, it had been

Natural gas plants in the U.S. are coming under increasing pressure from regulators and environmental groups

awarded a "reliability must run" designation by the California Independent System Operator (ISO).

However, the CPUC challenged that action, arguing that energy storage projects could be more economic than classifying the Metcalf Energy Center as a must-run power plant. Separately, another merchant plant owner, NRG Energy Incorporated, asked the CPUC for a delay in considering its application to build a 262 MW Puente Power Plant for Southern California Edison (SCE).

In yet another development, in April 2018, the Glendale, California, City Council placed a hold on plans to repower the 80-year-old Grayson Power Plant, a 500 MW gas-fired generator. Instead, the city council instructed the local utility, Glendale Water & Power, to more fully investigate cleaner, non-emitting electric options.

Finally, on one of its last legislative days in the 2018 session, California lawmakers adopted a plan to require all retail electricity to be carbon free by 2045.

Even before the state legislature acted, the trend against gas-fired generation was becoming apparent in regional projections for fuel types in new-build generation in various regions.

States on the west coast plan to build only about 5,557 MW of gas-fired generation over the next five years, down 72% from their plans only one year ago when natural gas was scheduled to account for about 49% of new generation built between 2018 and 2022. Given California's 100% carbon free mandate, the region's number of new-build gas plants may drop further.

Other states in the West, including Oregon and Washington, have upped their renewable portfolio standard (RPS) in recent years or adopted mandates to lower carbon emissions. These are critical factors that may cause regulators, utilities, and developers to rethink gas power in those states.

But there is a different picture in other parts of the country. Several regions, including the Great Lakes, the Northeast, the Mid-Atlantic, and the Southwest, plan to dramatically increase their fleet of gas-fired generators over the next five years.

Renewables outlook

Renewable generation is expected to account for about 57.4% of all new-build power projects over the next five years. On a percentage basis, the areas that have turned most sharply to sun and wind are the Midwest, Rocky Mountains, West Coast and New England regions.

In terms of raw numbers, the Rocky Mountains, with plans to build 24,339 MW of renewables over the next five years, edges out the Midwest (22,568 MW), the Southwest (17,751 MW) and the West Coast (15,571 MW) as the region most enthusiastically going for renewable energy.

Within the renewables segment, measured by "fuel," there is far more installed wind generation than solar generation in the U.S. Near-term plans to build more wind turbines continue to outnumber plans to build solar generation (Figure 3).

But wind power developers are battling something that solar power developers are not: financial incentives that decline by the year. Boom and bust cycles created by tax incentives play a large role in what amount of renewable generation moves forward in a given year. The federal production tax credits (PTCs), which benefit wind, continue to decline.

When Congress last extended those PTCs in late 2015, it wanted to incent developers to get steel in the ground sooner rather than later. For each year between 2016 and 2020, tax credits are lowered 20%.

Companies that broke ground on a wind project in 2016 were eligible to receive 100% of the 2.3 cents per kilowatt-hour PTC. Companies that broke ground on a project in 2019, by contrast, will only be eligible for 40% of the credit less than $0.01/kWh. By yearend 2020, the credits sunset.

Not surprisingly, developers responded as incented: 52 projects valued at about $14.7 billion were completed in 2016 compared to

44 projects worth $12.7 billion finished in 2017. Preliminary estimates show that seven projects with total generating capacity of about 1,200 MW and valued at $2 billion are scheduled to start operating in 2018.

In mid-2018, a Nebraska utility reportedly signed a power purchase agreement for wind at $11/MWh. That number, if confirmed, would represent a historic low price for wind power.

Meanwhile, the sun continues to rise for solar power. The solar industry's Investment Tax Credits (ITCs) were extended for five years in late 2015. Projects that begin construction before yearend 2020 are eligible for the full 30% tax credit. Projects breaking ground after 2020 would be eligible for less federal largesse.

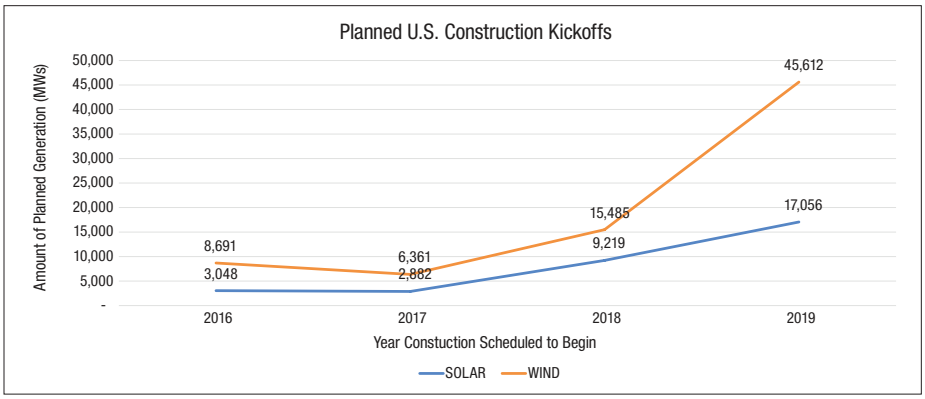


Figure 3: Planned construction kickoff dates for U.S. Wind and Solar projects. *Source: Industrial Info Resources*

Predictably, 2016 saw a surge of U.S. solar power development: 76 projects worth about $13.4 billion were completed that year. The next year, 77 projects worth $5.9 billion began operating. Preliminary estimates were that 32 solar projects valued at about $2.75 billion would come online in 2018.

Over the next few years, there is no shortage of work for renewable power developers, whatever their fuel. But developers are expected to keep a close eye on the calendar, as additional extensions of the PTC or ITC seem unlikely at this time.

Renewable energy may be the ultimate bipartisan energy issue, with broad and strong support from Republicans and Democrats across numerous states. But predicting what could happen in two years' time, when the PTC sunsets and the ITC starts declining, seems like a fool's errand.

The Trump administration's decision to levy a 25% tariff on imported steel, plus tariffs on imported solar cells and panels, enacted in early 2018, scrambled the economics of several thousand MWs of proposed renewable energy projects.

Nuclear outlook

The U.S. nuclear renaissance has officially receded in the rear-view mirror. The owner of Iowa's Duane Arnold Nuclear Power Station in mid-2018 joined the owners of nuclear plants in Nebraska, Vermont, Massachusetts, New York, New Jersey, California, and Wisconsin in deciding to prematurely retire operating nuclear plants.

The reason: cheap, abundant natural gas and, in some areas, high-quality wind or solar resources, that make gas, wind and solar power a more competitive alternative to nuclear (or coal).

In recent years, some states, including Illinois, New York and New Jersey, have enacted financial aid packages to keep uneconomic nuclear plants in their states open. But other states, including Connecticut, Ohio and Pennsylvania, have resisted financially propping up uneconomic nuclear plants.

Rebuffed by lawmakers in Ohio and Pennsylvania, FirstEnergy Solutions, the merchant-power unit of FirstEnergy Corporation, filed for Chapter 11 bankruptcy in early 2018 and began notifying regulators of plans to deactivate its three nuclear units: Davis-Besse (planned deactivation date, May 2020), Perry (May 2021) and Beaver Valley (Unit 1: May 2021; Unit 2: October 2021).

Those three plants have combined generating capacity of 4,048 MW. The two Ohio plants, Perry and Davis-Besse, generated nearly 90% of the Buckeye State's carbon-free generating capacity.

During the summer of 2017, after investing an estimated $9 billion to build two new units at the V.C. Summer Nuclear Power Station in South Carolina, the owners terminated that project. Following that decision, investigators, litigators, lawmakers and customer advocates swarmed over owners South Carolina Electric & Gas and Santee Cooper. Several executives departed, and the new leaders confronted the prospect of forced sales and dramatic electricity price reductions to refund some of the billions collected from customers for nuclear generation that will never operate.

Meanwhile, in Waynesboro, Georgia, where Georgia Power Company is adding two new units to its Alvin W. Vogtle Nuclear Power Station, costs continued to escalate. In late 2017, the Georgia Public Service Commission accepted Georgia Power's recommendation that construction continue. The project as originally budgeted in 2001 was projected to cost about $7.5 billion, but by late 2017 new cost estimates put the capital cost at about $25 billion.

At the end of 2017, regulators unanimously agreed to let construction at Vogtle to continue. Nine months later, in August 2018, Georgia Power said costs to complete the project jumped again, by about $2.3 billion, to over $27 billion, not including financing costs. The in-service dates remained November 2021 for Unit 3 and November 2022 for Unit 4.

The main reason for the cost escalation, Southern Company Chief Executive Officer Tom Fanning told investors, was scarcity of skilled craft labor. There were about 7,000 workers at the Vogtle site, 1,100 of which were electricians and pipefitters. But in an early August earnings call with analysts, he estimated an additional 600 electricians were urgently needed.

With the cancellation of the Summer project and the continuation of the Vogtle project, no other nuclear generators were under construction in 2017. And, with the exception of Utah's Blue Castle project, no other nuclear projects are scheduled to begin construction for the next five years.

A big part of the reason for nuclear power's recent troubles was Westinghouse Electric Corporation's decision in March 2017 to declare Chapter 11 bankruptcy and exit the new-build nuclear construction business. But that was not the first sign that all was not well in the nuclear world.

In recent years, one utility after another deferred, then cancelled, plans to build new nuclear units. Nuclear turned out to be a bet-the-company proposition where the rewards for success were modest, but the cost of failure was catastrophic.

Aside from new-build, project activity in the nuclear area over the 2019-2023 period is limited to small modular reactors (SMRs), dismantlement and demolition of shuttered plants and in-plant capital projects like steam generator replacements and controls upgrades. No nuclear uprate projects are on the horizon for the next five years.

Battery energy storage systems

In recent years, utility-scale battery energy storage systems (BESS) have gone through an intense phase of research & development, pilot demonstrations, and full-scale commercial deployments, all aided by supportive regulatory decisions. Early successes have moved this category of tech-

nology closer to the center of the electricity business from its former position at the industry's periphery. Indeed, BESS now is the belle of the electricity ball.

Even its staunchest advocates do not claim BESS will fix all that bedevils wholesale and retail electric markets. But battery storage is seen by a growing number of decision makers as a valuable, flexible and multi-purpose resource. Over the next five years, we anticipate utility-scale BESS will become a multibillion-dollar business. We expect to see at least 1,300 MW of BESS projects operating by year-end 2020. The number could be considerably higher.

BESS got a lot more attractive following a favorable ruling from Federal Energy Regulatory Commission (FERC) in early 2018. That opened wholesale markets to energy storage on an equal footing with generators and other resources. The industry spent a lot of time and effort in 2018 trying to figure out how that could work and what it might look like.

In that order, FERC instructed each of the nine organized regional transmission organizations (RTOs) and ISOs where it has jurisdiction to return to the agency by year-end 2018 with a plan to remove obstacles to considering storage on a level playing field with other resources. According to news reports, the nation's largest organized market, PJM, has deployed over 250 MW of battery energy storage projects since 2013.

A few years ago, California utility regulators got the BESS ball rolling in a big way when they issued specific mandates for energy storage projects, triggering an avalanche of bids for utilities in the Golden State. Battery energy storage projects helped utilities in California keep the lights on through the retirement of the San Onofre Nuclear Generating Station, the loss of the Aliso Canyon natural gas storage facility and the scorching summer of 2017.

Across the nation, battery storage projects of various sizes and purposes were being procured and deployed. Assuming they perform as planned, we expect the pace of procurements and deployments to accelerate over the next five years.

BESS projects are being used to defer capital outlays on a utility's transmission & distribution (T&D) system, provide voltage support, reshape customer electric demand, get around distribution transformer bottlenecks, and help electric utilities keep the lights on during emergencies or operational challenges.

Some executives have termed storage "the Swiss Army knife of energy." Costs have declined rapidly — about 70% over the last three years, by one estimate, helping drive more pilots and full-scale commercial deployments.

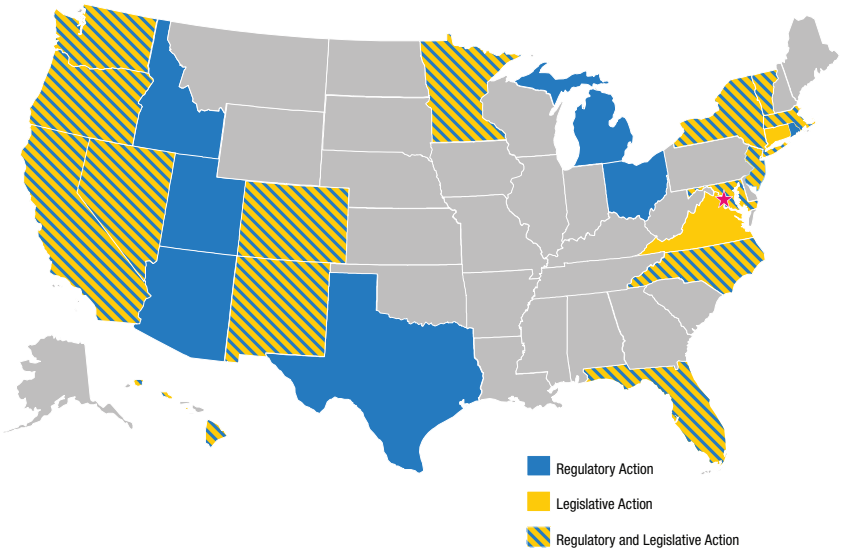


Figure 4: Map of energy storage regulatory and legislative activity.
Source: Energy Storage Association

Storage could create more optionality for utilities, which means it can have a lot of value. Rather than investing heavily to build costly new generation or T&D infrastructure, utilities increasingly are warming to storage as a smaller-scale resource with lower costs, faster installation times and more targeted deployments compared with traditional generation or T&D projects. Utility-scale BESS could reshuffle the economics of the electricity business.

If storage projects can help utilities burnish their environmental credentials, so much the better. BESS could help California attack its so-called "duck curve" problem, where renewable generation produces far more electricity than is needed during peak demand hours, forcing the cycling of other plants that are not designated as "reliability must run."

And in Texas, the Great Plains and the Midwest, when winds gust at 3 a.m. but no one is using electricity, storage could play a huge role in making more efficient use of those area's abundant wind resource and large installed base of wind generation.

BESS projects were an important part of responses to a request for proposals (RFP) issued by Xcel Energy subsidiary Public Service Company of Colorado (PSCo) at the end of 2016. In mid-2018, after weighing all the bids, the utility approached state utility regulators with a long-term energy plan that included 275 MW of electricity-storage projects.

In disclosing the details of the bids, PSCo said the median price of bids for wind + battery storage was $21 per MWh. The median price of bids for solar + battery storage $36 per MWh. Unlike average prices, median prices reflect an equal number of price points above and below the median number. So, there is reason to assume battery storage will soon be making a large splash across Colorado.

A growing number of other states are looking at BESS in a more favorable light. The list of states exploring, or committing to, some level of storage is long and getting longer every day. Besides California and Colorado, others include New York, New Jersey, Massachusetts, Florida, North Carolina, Illinois, Hawaii, Oregon, Arizona, and Nevada (Figure 4). As the technology proves itself to be reliable and cost-effective, that list is expected to grow over the next five years.

In mid-2018, Arizona Public Service Company issued an RFP to add up to 106 MW of battery storage to its solar plants. The utility said that bid was part of its 15-year plan to add up to 500 MW of battery storage.

IIR is tracking 30 utility-scale battery storage projects valued at about $2 billion that are scheduled to begin construction over the next five years. That number should grow over the next five years, depending on regulatory mandates and the outcome of early deployments.

One market research firm predicted lithium-ion battery-storage projects will fall below $200/kWh in 2019. Regardless of the exact price point, all sides agree the price trajectory is moving down, making storage an increasingly viable product that could provide value to utilities in a wide range of settings.

Microgrids and distributed generation

Like utility-scale BESS, microgrids now are being viewed more favorably both by utilities as well as non-utility organizations. The U.S. market for microgrids continues to build, driven by utility efforts to

make their T&D networks more resilient, particularly after natural disasters like Superstorm Sandy in 2012 and hurricanes Harvey and Irma in 2017.

Aside from utilities, large power-sensitive customers, such as hospitals, data centers, distribution centers and local governments, are spending more time investigating how microgrids could make them less susceptible to the vicissitudes of severe weather and utility operations. Currently, microgrids capable of distributing more than 1,500 MW of electricity are operating in the U.S. Another 3,000 MW could be added by the end of 2020.

Engineering and consulting firms are doing a brisk business assessing microgrids. The U.S. Department of Energy has a robust grant program issuing funding for several ongoing and future studies.

Like BESS and microgrids, distributed energy resources (DERs) continue to grow in importance, a trend that should continue for the next five years. Right now, there are an estimated 3,000 MW of distributed solar and wind, fuel cells, small-scale combined heat and power (CHP) and internal combustion projects in operation in the U.S. DER deployment is being driven by corporate clean-energy pledges and rooftop solar power.

But microgrids do have their challenges, including regulations, costs, and a rapidly evolving base of knowledge. Regulatory challenges include how to craft net metering 2.0 regulations that will not disadvantage those customers who cannot or choose not to install DERs. But the DER market has grown rapidly, to an estimated base of about $150 billion by 2016, and we expect nearly another $170 billion will be invested by 2020.

Looking ahead

Advanced technology, dynamic regulatory mandates, and shifting fuel and capital costs continue to roil the power generation business. Consumer preferences increasingly are playing a role in the industry's tumult, as residential and commercial customers in one state after another tell their regulators and power providers they do not mind paying slightly more, if they have to, for electricity with beneficial environmental attributes. In some cases, there is no longer a "green premium" for purchasing renewable or carbon-free electricity.

Consumer preferences appear to be something some industry veterans have trouble accepting and internalizing. For an industry long based on scale and cost/kWh, factoring the diverse needs and wants of customers into capital budgets and operating plans produces a bit of a deer-in-the-headlights look. But for those that are uncomfortable with the pace of industry transformation, there is no sign it will slow down any time over the next five years. ■

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