U.S. POWER INDUSTRY OUTLOOK 2017

THE OBAMA ADMINISTRATION SPENT EIGHT YEARS WRITING RULES THAT FUNDAMENTALLY ALTER THE NATION'S ELECTRICITY GENERATION BUSINESS. WILL THE CLEAN POWER PLAN BE SUSTAINED BY THE COURTS? THE ANSWER MAY DEPEND ON THE VOTERS.

BRITT BURT, AND BROCK RAMEY
INDUSTRIAL INFO RESOURCES

Oral arguments over the Clean Power Plan (CPP) were scheduled to be heard by the U.S. Court of Appeals for the D.C. Circuit in late September. A decision is expected in early 2017, if not late 2016. After that ruling, all parties are expected to take the short walk over to the U.S. Supreme Court for a final decision on the legality of President Obama's signature energy and environmental rulemaking.

Whether the appeal is heard by eight or nine Supreme Court justices may turn on the outcome of November's presidential, House and Senate elections. During the summer of 2016, once each party's respective standard-bearer was evident, Democrats and Republicans conducted war-gaming exercises over filling the court's empty seat. All options turned on what the voters decide November 8.

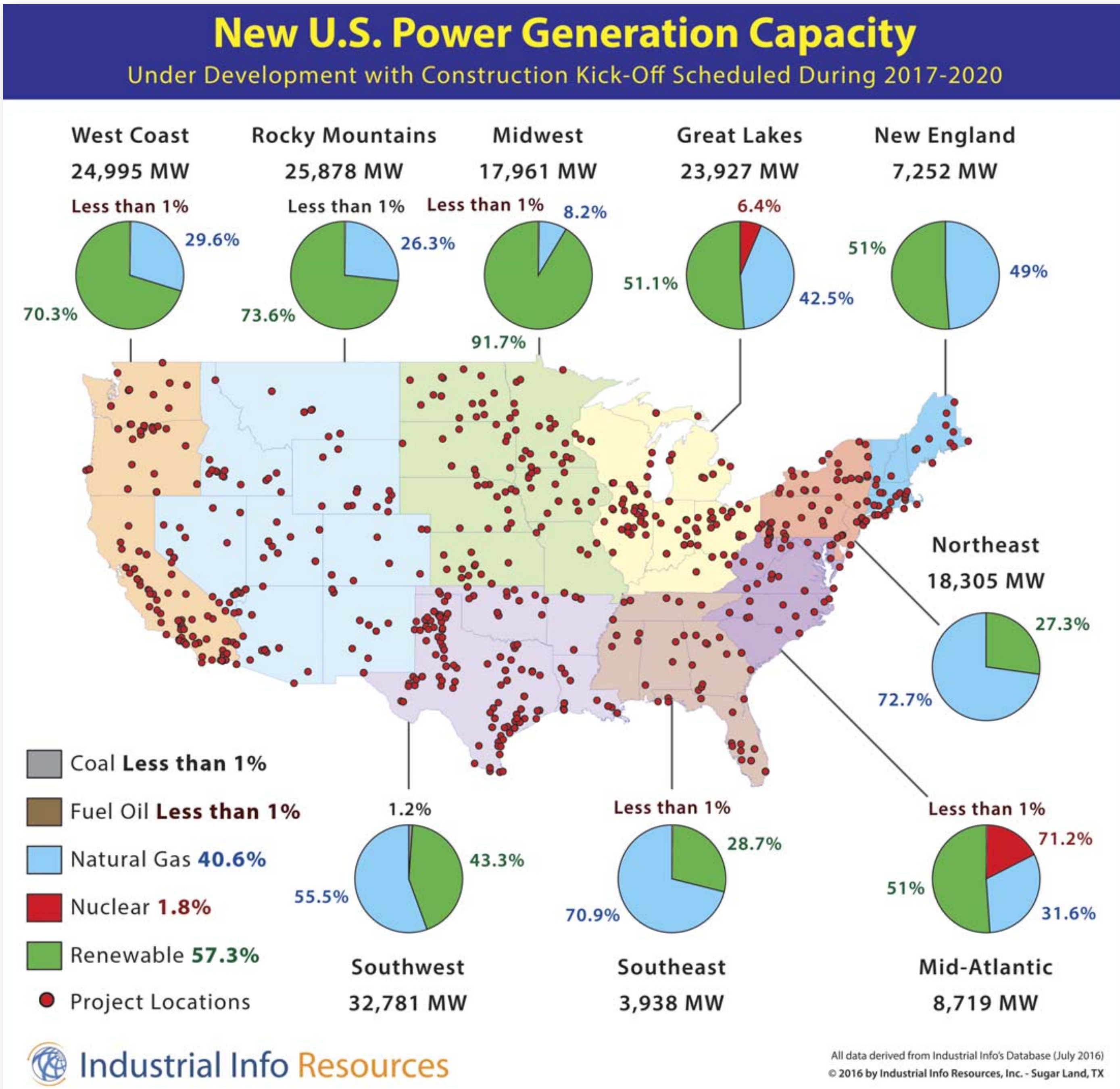

Figure 1: Renewables and natural gas generation are virtually the only two sources of new electric generation that are expected to be built between 2016 and 2020.

Source: Industrial Info Resources

Figure 2: The Pagbilao coal plant in the Phillipines operates with steam turbines by Mitsubishi Hitachi Power Systems

Overview

The CPP would accelerate trends already evident in the U.S. electric generation business. Coal would lose its longstanding claim as the leading fuel for electric generation, supplanted by natural gas. Renewable generation would continue its expansion. Nuclear power would be squeezed by economics and regulatory fiat.

Energy efficiency and other customer programs designed to reduce or shift electric consumption would be ascendant, as would rooftop solar and other forms of distributed energy resources.

If energy efficiency and distributed energy resources succeed as regulators and rulewriters hope, transmission development also will likely suffer collateral damage. Rather than building numerous high-voltage transmission lines to carry renewable energy hundreds of miles from remote central-station sites, consumers would be able to flip a switch and either self-power or sell unused electricity back to the grid.

Billions of dollars of power plant and transmission projects will be affected by the Supreme Court's CPP decision. Even though the court's decision may be at least another year away, the broad trends of the nation's electric generation business already are clear. Natural gas and renewable energy are virtually the only types of power plants expected to be built over the next five years.

That may change when the Supreme Court hands down its decision, but until then, the outlook for the power market in the U.S. is green and gassy (Figure).

Project development data tracked by Industrial Info Resources (IIR) sees renewable energy and natural gas dominating the new-build power market between 2017 and 2021.

In fact, the map of U.S. power development has gotten even greener over the last year, with renewable energy expected to account for about 57.3% of all new-build project activity for the next five years, up from 55.3% for the 2016-2020 period. Gas-fired generation is projected to account for about 40.6% of all new electric generating capacity that will be built between 2017 and 2021.

The regions with the greatest concentration of renewable energy development over 2017-2021 are the Midwest (where renewables are projected to account for 91.8% of all new-build generating capacity), the Rocky Mountains (73.6%, down a touch since last year) and the West Coast (70.3% of all new-build generation project activity).

By contrast, the Northeast and the Southwest are expected to see the least amount of renewable power project development over the coming five years. Both regions have largely tied their fates to natural gas, though in the Northeast it remains an open question whether the necessary gas pipeline infrastructure can be built in time to meet projected demand growth.

New power project development has become a two-fuel race in the several regions, with gas and renewables being the only fuels in contention. The Midwest is split 92%/8% between renewables and gas while in New England the split is much closer, 51%/49%.

In the Northeast, gas-fired power development leads 73% to 27%. In the Rocky Mountains, new-build coal has a tiny slice of the project development market, which is otherwise dominated by renewable energy over natural gas, 73.6% to 26.3%.

Coal interests have long seen energy and environmental rulemakings as a "war on coal." But low-priced natural gas, congressionally backed incentives for renewable energy and state regulatory mandates to increase renewable energy, distributed energy resources (typically rooftop solar) and energy efficiency, also played key roles in dethroning King Coal as the leading fuel for electric generation in recent years.

The five-year extension of the federal Production Tax Credits (PTC) and Investment Tax Credits (ITC) at yearend 2015 helped bolster the competitiveness of wind power and solar energy compared to other fuels for electric generation.

In fact, 2016 will be the year that gas-fired generation surpasses coal-fired generation on an annual basis for the first time, according to the July 2016 Short Term Energy Outlook from the U.S. Energy Information Administration (EIA).

That agency projected gas will generate about 34.2% of the nation's electricity this year to coal's 30.2%. Next year the gap is expected to shrink a bit, but gas is expected to keep its lead. In 2017, EIA forecasts gas will generate about 33.3% of the nation's electricity to coal's 31.1%.

Coal outlook

Coal Country is holding its collective breath as the CPP makes its way through the federal courts. Mining companies have let an estimated 211,000 miners go since September 2014, according to the U.S. Department of Labor's Bureau of Labor Statistics. King Coal has been fighting economics and public policy for years, and coal continues to lose. Coal consumption in 2016 is on track to be the lowest since the early 1980s.

Coal companies and coal-burning utilities have their proverbial fingers crossed for a positive ruling from the highest court in the land. Development of new-build coal-fired generation has been virtually non-existent in recent years. Most coal-related capital spending over the next five years is expected to go to in-plant capital projects like installation of environmental controls, efficiency upgrades and demolition of shuttered plants.

Industrial Info is tracking 33 coal capital projects valued at $11 billion that are scheduled to be completed in 2016. Most of these projects are environmental retrofits, but more than half of the $11 billion in coal-relate capital projects is tied to one plant: the Kemper County integrated gasification combined cycle (IGCC) project in Mississippi.

The Kemper County plant has caused heartache for its owner, Mississippi Power, a unit of The Southern Company. The project is billions of dollars over budget and years late in completion. What was once considered a potential lifeline for coal-fired power has instead become a millstone.

The experience of Kemper County, and another IGCC plant, Duke Energy's Edwardsport plant in Indiana, likely will deter any utility from deploying IGCC technology for years to come.

Another once-hoped-for salvation for coal power, carbon capture & sequestration (CCS), also took a step backward in 2016, which likely will chill future enthusiasm for that approach to lower carbon dioxide emissions from coal-fired power plants.

The world's first commercial-scale deployment of CCS, at SaskPower's Boundary Dam power plant, came online in 2014. It was designed to remove up to one million tonnes of CO_2 annually from a 115 MW coal-fired generator. It cost about $1.2 billion to build, including hundreds of millions of dollars in government grants.

But in 2016, details emerged about Boundary Dam's significant under-performance, which cast a new light on its cost and cost-effectiveness. News reports have circulated that the plant has been plagued by multiple shutdowns, has fallen well short of its emissions targets, and faces an unresolved problem with its core technology.

The costs, too, have soared, requiring tens of millions of dollars in new equipment and repairs. One Canadian lawmaker said the project's economics went from dubious to disastrous.

In Thompsons, Texas, about 1,600 miles away from the Boundary Dam project, NRG Energy officials had already reached the same conclusion about the economic viability of CCS. In late 2015, as it considered construction reports on its Petra Nova CCS project at the W.A. Parish Power Station, NRG officials decided that project would be its first, last and only CCS project.

Petra Nova's construction is expected to be finished by yearend 2016. When it is, NRG and its co-owners will have spent an estimated $1 billion to capture 90% of the CO_2 from a 240-MW slipstream at Parish Unit 8. In fairness, the collapse of crude-oil prices also hastened NRG's decision, as the captured CO_2 was expected to be used in enhanced oil recovery (EOR) projects in Texas. Those projects make a lot of sense when crude oil sold for over $100 per barrel.

Figure 3: Natural gas power plant running Siemens SGT-100 gas turbines

But by the time NRG made its decision, oil was selling for less than half that.

Absent a revenue stream from EOR projects to defray its high costs, and lacking a government mandate, CCS projects face a dim future over the next five years. The federal government backed away from CCS in early 2015 when it pulled funding for the FutureGen 2.0 project in Illinois, a decision that followed over a decade of rising and falling federal government support for CCS technology.

Then, in mid-2015, the U. S. Department of Energy suspended funding for the Hydrogen Energy California IGCC project in California. The gradual withdrawal became a run when the DOE pulled funding for the Texas Clean Energy Project, a planned 400-MW IGCC, in mid-2016.

For the 2017-2021 period, Industrial Info expects to see virtually no U.S. new-build project activity. A total of 443 MW of coal-fired power projects are under development for that five-year period, virtually all of it in the Southwest.

Despite the grim outlook for new-build coal, Industrial Info is tracking over 300 capital and maintenance projects at the nation's coal plants with a collective value of about $6.5 billion that are scheduled to begin between 2017 and 2021.

These scheduled projects include installing environmental upgrades, converting plants to burn natural gas, upgrading the plant's water cooling system and performing various types of in-plant maintenance work.

Two recently approved environmental regulations that will significantly affect coal-fired generation are the Coal Combustion Residuals Rule (CCR), published in the Federal Register in April 2015, and the Effluent Limitations Guidelines (ELG), finalized in late 2015. Both these regulations are expected to lead to large amounts of spending at coal facilities.

The CCR rule, approved by the U.S. Environmental Protection Agency (EPA), required wet ash landfills to either convert to dry ash facilities or transport wet ash product to other locations. Utilities are working to convert fly ash and bottom ash to dry products and bring their onsite ash ponds into compliance.

EPA estimated it would cost coal-fired generators a total of about $509 million annually to comply with the CCR rule. But individual companies have reported costs ranging from $50 million to $300 million to comply with the new rule. Utilities have until the end of 2018 to have plans in place on how to deal with these facilities.

The ELG rule, promulgated under the Clean Water Act, seeks to reduce the amount of toxic metals, nutrients, and other pollutants that steam electric power plants emit. Affected facilities include any plant that has flue gas desulfurization, fly ash, bottom ash, or flue gas mercury con-

(Continued on p. 14)

trols, or burns gasified coal or petroleum coke products to generate electricity. The agency estimated compliance costs at $480 million, but we should not be surprised if that sum understates the industry's actual compliance outlays.

The compelling economics of natural gas extracted from shale formations has long put coal on the defensive. Some "black swan" event that strips gas of its economic advantages could shift the competitive dynamics of the fuel wars and give Coal Country hope. For example, a federal rule limiting the extraction of gas using hydraulic fracturing would drive gas prices sharply higher and could breathe new life into coal-fired generation.

Black swan events, by their nature, have a low probability of occurring but a high impact when they do take place. Gas at the Henry Hub briefly sold for about $2 per million British thermal units (MMBtu) in early 2016, but in 2005 and 2008 it briefly sold for over $10 per MMBtu, which helped choke off previous gas-fired power build-outs. The consensus about gas prices today, however, is "lower for longer."

Natural gas outlook

This past year was a busy one for developers of gas-fired electric generation, and we expect the next five years to be busy as well. Even if the CPP is overturned by the Supreme Court, gas-fired power development is expected to continue surging. If the CPP is sustained by the court, gas-fired power development is expected to zoom forward, both as a generating source itself as well as a backup for intermittent generation like wind and solar.

Several billion-dollar gas power projects broke ground in 2016, and we see a number of other mega-projects breaking ground over the next five years.

Florida and Virginia, two states with high electric demand growth and a legacy of coal-fired power, are expected to continue as leading states in the gas power movement. Texas and California also are poised to deepen their reliance on gas-fired power, as is the Northeast and New England.

But plans to bring natural gas from the Marcellus and Utica shales to New England and the Northeast hit a bump in 2016 after two planned natural gas pipelines were shelved by developers. Although other projects are poised to take the place of these fallen projects, any delays in siting gas pipelines to bring gas to New England will be cause for concern among electric generators there.

The regions with the greatest percentage of gas-fired power development for 2017-2021 are the Northeast (72.7% of all new-build generation projects by MW), the Southeast (70.9%), the Southwest (55.5%) and New England (49%).

Figure 4: Ivanpah solar plant in California

The North American Electric Reliability Corporation (NERC) has identified New England and Texas as two regions where over 50% of electricity is generated by natural gas. At an industry conference, an NERC official said the agency's concern about over-reliance on gas generation was "at least a 7 on a scale of 1-10."

New England was one of several regions that experienced the consequence of the Polar Vortex of 2014, when a deep freeze caused gas and power prices to shoot upward temporarily. Coal kept the lights on in New England as well as other places.

Coal was not able to come to the rescue of Southern California in 2016 following the discovery of a leak in the Aliso Canyon gas storage facility. With that facility out of service and given Southern California's high reliance on gas-fired power, the onset of summer brought a bevy of warnings about potential blackouts if generators were unable to import enough gas to keep the power plants humming as customers cranked on their air conditioners.

Renewables outlook

Renewable energy developers cheered the late-2015 extension of federal tax credits for wind power and solar power. The five-year extensions, which included a sliding-scale proration of the tax credits, were designed to spur developers to getting steel in the ground sooner rather than later.

And developers did not disappoint. Industrial Info is tracking 151 renewable energy projects that are scheduled to begin construction in 2016. The value of these projects is about $23.3 billion. We do not expect all of those projects to kick off as scheduled.

Some will be pushed back, the victim of an inability to secure either financing or a power-purchase agreement (PPA). We anticipate some of these planned projects will be cancelled. Still, the pipeline is brimming with renewable energy projects.

California, Texas, Kansas and Oklahoma are on track to be the leading states for renewable power projects scheduled to begin construction in 2016. For the 2017-2021 period, Industrial Info is tracking 424 projects valued at $132.25 billion. The states leading the pack for that five-year period are Texas, North Dakota, California, Arizona, New York and Illinois.

The sliding scale federal tax credits for renewable energy, passed at the end of 2015, incented developers to begin work on projects quickly, and developers got the message. Developers who begin construction of eligible projects in 2016 stood to reap 100% of the 2.3 cents per kilowatt-hour (kWh) of electricity produced for as long as 10 years.

(Continued on p. 16)

Those who waited until 2017 to begin construction stood to receive 80% of that tax credit, and developers who wait until 2018 to begin construction will be eligible for only 60% of the tax credit, equal to about 1.38 cents per kWh produced.

States also supported renewable development by increasing their renewable portfolio standards (RPS). California in 2015 determined that 50% of its electricity must come from renewable sources by 2030. Oregon doubled its RPS, to 40% by 2040, during 2016. Twenty nine states, Washington, D.C. and three territories have RPS while another eight states and one territory have non-binding renewable energy goals.

Continued cost declines for wind power and solar energy were behind some state announcements. Solar panel costs reportedly declined over 80% since 2008, from $4 per watt to $0.65 per watt, according to a solar industry survey. The cost of wind power has declined 66% over six years, according to a wind energy trade group.

For wind power production in a state, Iowa leads the nation: 31% of its generated electricity comes from wind. And that may surge further, as there are seven other wind farms under development in the state.

The value of these projects approaches $3 billion, and their aggregate generating capacity is about 1,622 MW. All of these projects are scheduled to be operating by 2018, which would mean roughly 4 in 10 of the megawatts generated in Iowa would come from wind turbines.

Other states that generate a high percentage of electricity from windpower include South Dakota (25.5%), Kansas (23.9%), Oklahoma (18.4%), North Dakota (17.7%), Minnesota (17%) and Idaho (16.2%), according to the EIA.

Farmers, one of the greatest beneficiaries of wind power's largesse in the form of lease and access payments from owners, also are some of wind power's greatest foes. It all depends on where you live, what you value and how you make your living.

Although plenty of farmers are happy to cash checks from wind power owners, Missouri farmers have not been so easily mollified. They have successfully pressured the state's public service commission to reject a large interstate transmission project, Grain Belt Express, which, if built, would transport up to 4,000 MW of renewable energy from the Southwest Power Pool, mainly Kansas, to locations in the Midcontinent Independent System Operator (MISO) and the PJM Interconnection.

The federal government already pushed through one stalled interstate transmission project in 2016, the Plains & Eastern Clean Line, which Clean Line Energy Partners was developing, drawing howls of outrage from Arkansas lawmakers and regulators who felt big-footed. Will Uncle Sam intervene again for the developer's sibling line, Grain Belt Express, currently stalled in the Missouri mud? It wasn't clear at press time, though Grain Belt's owners have refiled their application with Missouri regulators in mid-2016. That $2.5 billion, 700-mile transmission line would stretch from the Oklahoma panhandle to western Tennessee.

State regulators may rail against getting big-footed by the federal government, but in its justification for getting involved in the Plains & Eastern Clean Line flap, the DOE notes it is acting under authority explicitly granted to it by its predecessor, George W. Bush, who signed the Energy Policy Act of 2005 after it passed Congress with strong bipartisan support.

Figure 5: Legislation such as the Clean Power Plant act seeks to reduce emissions at coal- and gas-fired plants. Pictured here is the FPL's West Country Energy Center, which runs on natural gas

Nuclear outlook

Was Pacific Gas & Electric's decision to not relicense its Diablo Canyon nuclear plant, and replace its foregone output with non-greenhouse gas-emitting resources, a look at the future of electricity generation, or a California anomaly? PG&E was not the only utility that decided to remove nuclear power from its resource portfolio in 2016.

The Omaha Public Power District did the same thing. Exelon decided to shutter two of its Illinois nuclear plants because they were uneconomic. And in late 2015, Entergy decided to prematurely shutter nuclear plants in Massachusetts, New York and Vermont. Entergy and Exelon said their actions were driven by low-cost gas generation. Rather than continuing to fight the trend, they raised the white flag.

It is widely expected that gas-fired generation will replace the generation lost by shuttering the Quad Cities, Clinton, Pilgrim and Vermont Yankee nuclear plants. But unlike Entergy, Exelon or OPPD, PG&E was unique in its decision not to use natural gas-fired generation to replace the generating capacity lost when the two-unit Diablo Canyon stops producing power in 2024 and 2025, when its current licenses expire.

Placing its faith, and its future ability to keep the lights on, exclusively in energy efficiency, renewable resources and electricity storage, was a strategic step that could shake up the electric generation business. The wisdom (or folly) of PG&E's decision will not be clear for several years.

The utility's bold proposal, unveiled this past June after lengthy collaboration with labor and environmental groups, will be considered by the California Public Utilities Commission in 2017. If approved, it will be implemented in three phases starting in 2018.

The proposal did not come with a specific price tag, though PG&E officials said their alternative was cheaper than continuing to run Diablo Canyon, which came online in1985. Nuclear power accounted for about 23% of PG&E's electricity in 2015.

(Continued on p. 18)

The San Francisco-based utility is not proposing to replace all of Diablo Canyon's 2,240 MW of generating capacity. Public policy measures enacted by California are allowing tens of thousands of customers across the state to erect rooftop solar panels as well as form community choice aggregation entities, which will buy power at wholesale on behalf of its members. Those measures are expected to shave thousands of megawatts off the state's electric demand.

Public policy, not economics, proved to be Diablo Canyon's undoing. California legislators determined nuclear power was not to be considered as a "clean" generating resource that did not emit greenhouse gases, even though it does not emit those gases.

Therefore, nuclear generation would not count towards the state's renewable portfolio standard (RPS) in the same way that federal officials, when finalizing the Clean Power Plan, decided nuclear utilities will not be able to shrink their carbon footprint using nuclear power.

That federal regulatory fiat, contained in the final federal Clean Power Plan rule released in August 2015, helped doom OPPD's Fort Calhoun nuclear plant, the nation's smallest at 478 MW of generating capacity.

The OPPD board decided in mid-2016 to stop generating power at Fort Calhoun by the end of 2016. The public power utility has aggressively repositioned its generating portfolio in recent years, adding hundreds of megawatts of renewable generation as well as embarking on an effort to lower electric demand by several hundred megawatts through energy-efficiency and other customer programs.

On the other side of the country, New York did what California and Illinois did not: Pass a measure that monetized the value of carbon-free electric generation. Under a multi-phase program adopted by New York utility regulators this past August, three nuclear generators in the Empire State became eligible for hundreds of millions of dollars of subsidies.

The three upstate New York nuclear plants eligible for a subsidy are the R.E. Ginna Nuclear Power Plant, Nine Mile Point Nuclear Power Station and the James FitzPatrick Nuclear Power Station. The first two are owned by a unit of Exelon Incorporated and the third is owned by Entergy Corporation, but Exelon has agreed to purchase it. All three were marked for early closure until the state stepped in.

New York Governor Andrew Cuomo has been trying to close the downstate Indian Point nuclear station, located about 43 miles north of Manhattan, and the governor's plan did not include a subsidy for that facility.

Nebraska, California, New York and many other states tightened their embrace of energy efficiency and other customer programs in 2016, which is expected to reduce the nation's electric demand growth, potentially even turning it negative, over the next five years. Public policy makers, using the tools of regulation, may accomplish what economics have not: slow the "dash to gas" in electric generation.

The Tennessee Valley Authority (TVA) completed construction of the Watts Bar Unit 2 nuclear generator this year. Construction of that unit began in 1972 but was suspended from 1985-2007. Once construction resumed, TVA spent an estimated $4.7 billion to finish construction of the 1,150 MW nuclear unit.

The completion of Watts Bar 2 leaves Vogtle Units 3 and 4, and Summer Units 2 and 3, as the only nuclear plants under construction. Both have reported significant cost overruns and multiple construction delays. Those factors, plus the loss of federal CPP credits for nuclear's carbon-free generation, have made new-build nuclear generation an unattractive proposition. That may change once small modular reactors (SMRs) are certified, licensed and built, but that won't happen before 2021.

Transmission & distribution

In addition to heavy project spending for different types of generation over the 2017-2021 period, electric utilities also have plans for robust spending on their transmission and distribution (T&D) networks.

In some regions, spending was up in 2016 for construction of 345-kilovolt (kV) projects. We expect spending to bump up in 2017 and 2018 before project activity reverts to its 2015-2016 mean. Some of the transmission projects proposed to comply with Order 1000 from the Federal Energy Regulatory Commission (FERC) have not moved forward as expected.

Some regions have cancelled projects, withheld support or found their decisions ensnared in litigation, such as the Clean Line Grain Belt Express project. Federal override of a state regulatory decision in the Clean Line Plains & Eastern transmission project could be a glimpse of future federal activism in breaking a logjam of transmission projects.

Delays in constructing liquefied natural gas (LNG) export terminals, and state energy policy decisions to support decentralized generation options like community solar gardens and rooftop solar power, suggest some transmission projects will be cancelled or delayed. Delays in power-plant retirements also will impact T&D spending during 2017-2021.

Industrial Info Resources projects T&D spending will range between $30 billion to $40 billion in 2017. A lot of the money will go to distribution projects and transmission line projects less than 138 kV. Renewable energy projects and oil & gas operations are expected to contribute meaningfully to T&D spending in the Rocky Mountain area. Texas may see an expansion of its CREZ networks, this time to send power from east to west. The potential to expand the California Independent System Operator (CAISO) before California and into several Western states could lead to a surge on transmission spending. When all is said and done, we expect that U.S. T&D spending for 2016 at between $25 and $30 billion.

Looking forward

The November election will set off a chain reaction of events that will, ultimately, have a significant bearing on whether the CPP is affirmed, or rejected, or partly affirmed and partly rejected. Members of the power industry should keep a close eye on the presidential election but also which party wins the Senate, where 24 Republican seats are up for election compared to 10 for the Democrats.

The Environmental Protection Agency (EPA) has built up a sizable record in the years it took to draft for CPP. That suggests that a new president can not simply yank that rule. Administrative procedures that govern executive-branch rulemakings do not let agencies withdraw a rule simply because the White House has a new occupant.

Although who becomes our 45th president is important to the power industry, the party that controls the Senate is even more important to the fate of the CPP. As baseball philosopher Yogi Berra once said, "It's tough to make predictions, especially about the future."

Britt Burt is vice president of Global Power Industry Research for Industrial Info Resources (IIR). Headquartered in Sugar Land, Texas, with five offices in North America and 10 international offices, IIR provides global market intelligence for companies in the power, heavy manufacturing and industrial process businesses.

Brock Ramey is North American Power Specialist for IIR. For more information see *www.industrialinfo.com* or email *powergroup@industrialinfo.com*