RRA REGULATORY FOCUS

Grid transformation and stranded costs: An old topic becomes new again

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Market Intelligence

Changing market and regulatory dynamics are raising concerns about the prospects of "stranded costs," but this is not really a new challenge for the electric industry. A recent S&P Global Market Intelligence webinar, Grid Transformation and Stranded Assets: Why They Could Be Back and Bigger Than Ever, delved into historical and future potential stranded costs and related market developments.

This article, the first in a two-part series, examines regulatory and policy factors that have led to stranded costs in the past and may lead to future stranded costs as well as regulatory/policy responses to this issue. A subsequent article will address related market developments.

<< View the presentation >>

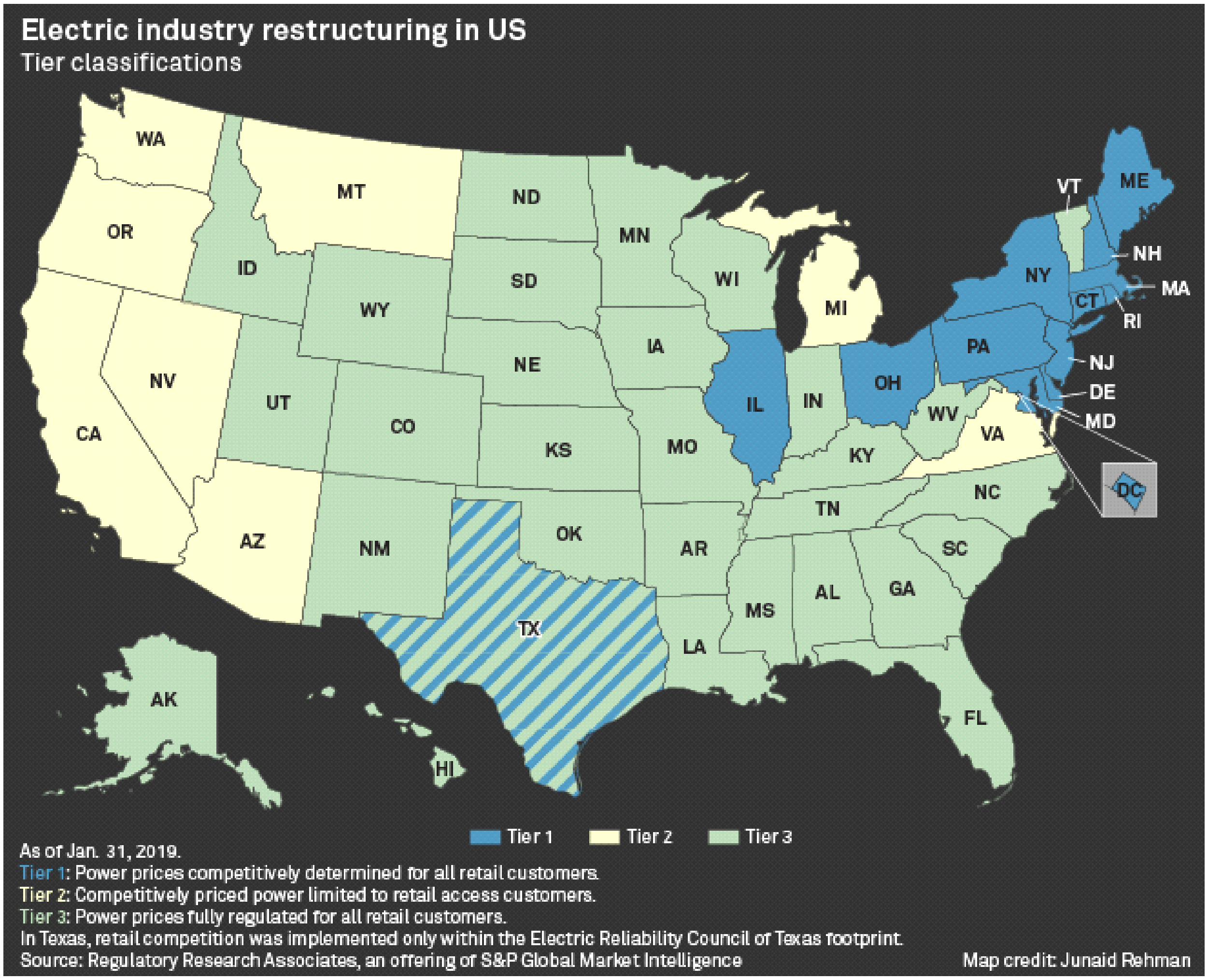
Canceled plant — 1980s stranded costs

In the mid- to late 1980s, stagnant load growth, cost increases to comply with more stringent regulatory standards, cost overruns on certain projects and poor financial health on the part of some utilities caused a series of generation projects to be abandoned prior to completion.
While those investments were referred to as "canceled plant," they were in essence assets that the utilities had built in good faith, often with the consent of regulators, that were never going to be used and useful for ratepayers.

The regulatory treatment accorded the sunk costs associated with these projects varied depending on how each state's statutes defined recoverable costs and whether the costs were deemed to have been prudently incurred. The ratemaking provisions ultimately approved ran the gamut from full recovery of the sunk costs, with a return on the investment, i.e., inclusion in rate base for a cash return, to complete denial of recovery, leading to large write-offs.

Electric industry restructuring — retail competition for generation service

The term "stranded costs" became popular in the mid-1990s as regulators and legislators grappled with the decision of whether to permit retail customers to select their generation providers. In the end, 13 jurisdictions moved to full retail competition for generation, while nine implemented retail choice for only a portion of the customers in each service territory.



In both instances, the assumption was that retail competition would result in lower generation prices, thus devaluing the generation assets that were going to be transferred to unregulated affiliates or sold to unaffiliated entities. Policymakers generally agreed that under the "regulatory compact," the utilities should be compensated for this devaluation as it stemmed from a change in the regulatory framework.

It is important to keep in mind that unlike the canceled plant of the 1980s, these plants had been found to be prudent and used and useful at some point in the past, were being used to serve customers and were included in the companies' regulated rate bases.
The difficult questions to be answered by regulators and policymakers pertained to how much should be recovered and through what types of mechanisms.

Most jurisdictions made an administrative determination of stranded costs based on the difference between the revenue stream the affected assets would receive under traditional regulation and the revenue stream expected to be achieved in a competitive market, subject to certain adjustments. This required regulators to make assumptions regarding what competitive power prices might be, and the stakeholders had divergent views regarding this as well as whether a return should be applied, whether there were any items that offset the balance to be recovered and over what time period the net stranded costs should be covered. The proceedings to address these issue were drawn out and contentious, despite state laws allowing recovery of stranded costs.

In the end, most states allowed the approved amounts, which were often much smaller than what the companies had sought, to be recovered over as many as 11 years, with some type of return or carrying charge on the unamortized balance.

In some instances, to reduce the cost of recovering this regulatory asset, the companies were permitted to securitize all or a portion of the balance, with the related bonds carrying low-risk interest rates and much longer terms.

In either case, the related revenue streams were recouped from customers via nonbypassable charges on distribution rates.

Stranded cost drivers today

Today, the specter of stranded costs is arising from a host of sources, and these sources have the potential to affect a broader array of asset classes.

Tightening environmental standards have been presenting challenges for coal-fired generation for some time, beginning with the enactment of federal clean air standards in the 1990s but most recently with the promulgation of the now-defunct Clean Power Plan. While its successor, the Affordable Clean Energy, or ACE, rule, has less dramatic potential impacts, thus far, it has not dissuaded plant owners who are planning to prematurely shut down coal facilities. Movements such as the Green New Deal, while not codified in policies, are being watched closely by industry stakeholders as the movements could portend additional negative repercussions for coal generation as well as state-level emissions-reductions initiatives.

Falling competitive power market prices, largely the result of lower gas prices brought on by the shale gas boom and the switch to lower-cost, more-flexible gas-fired resources are rendering coal and nuclear plants uneconomic or unprofitable.

Expanding state mandates for renewables, federal and state subsidies for these resources, and customer focus on environmental, social and governance issues are squeezing out coal and nuclear generation sources and could place gas-fired generation at risk in the not too distant future.

Shifts in the location of the resource mix due to the penetration of renewables are changing transmission needs and could ultimately lead to stranded investments in these assets.

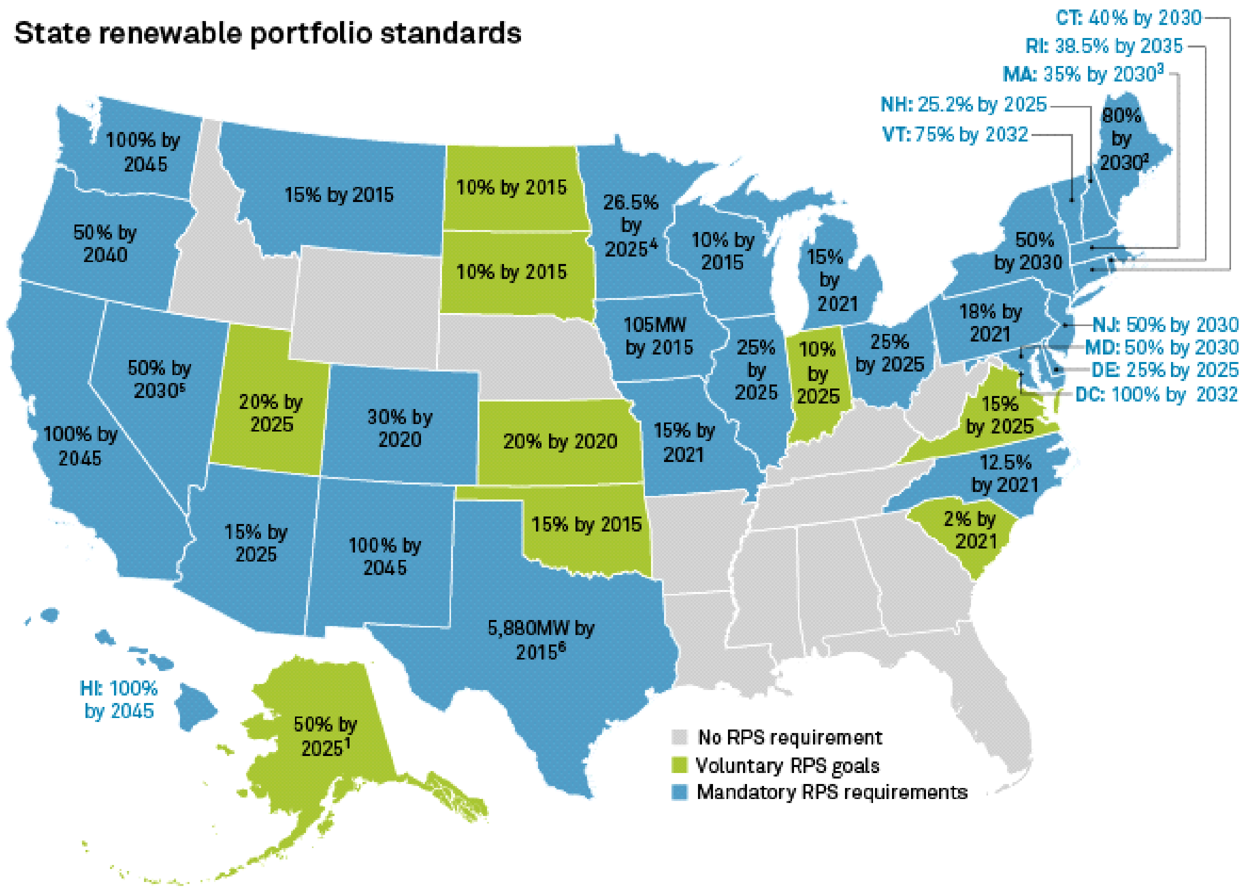
Similarly, decentralized configurations, such as distributed generation and microgrids, present potential threats to the utilities' ability to recover fixed distribution system assets and may lead to stranded costs in this segment of the industry. For now, assets that face the most immediate risk of becoming stranded are coal and nuclear generation, and those will be the focus of the remainder of this discussion.

Overview of renewables initiatives

Despite the lack of a federal mandate and the demise of the Clean Power Plan, as of July 8, six jurisdictions had enacted legislation expanding their renewable portfolio standards requirements in 2019. In 2018, four states had enacted such legislation.

As of July 8, when the data was gathered for the attached presentation, six jurisdictions — five states and the District of Columbia — had RPS goals in place that call for 100% of the generation sold in the state to come from renewable or carbon-free resources by 2050 or sooner. On July 18, New York became the seventh jurisdiction to implement a 100% clean energy target.

State renewable portfolio standards



Data as of July 8, 2019.
RPS = Renewable portfolio standard

[1] While the goal is not present in codified statues, House Bill 306, which sets the 50% RPS goal, was signed in July 2010 and went into effect that September.

[2] State statute also includes a goal of 100% renewables by 2050.

[3] The state's requirement is to increase by an additional 2% annually beginning in 2020 through 2029, after which it is to increase by an additional 1% annually indefinitely.

[4] Any electric utility that owned a nuclear generating facility as of Jan. 1, 2007, i.e., Northern States Power-Minnesota, generate or procure 30% of retail sales from renewables and an additional 1.5% from solar by 2030.

[5] In addition to the state's mandatory requirement, recently enacted legislation calls for an RPS goal of 100% carbon-free resources by 2050.

[6] Texas PUC rules call for the utilities to "ensure that the means exist to achieve a target of 10,000 MW of installed renewable capacity by January 1, 2025."

Map Credit: Arleigh Andes
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Nevada, New Mexico, Washington state and the District of Columbia had enacted 100% RPS mandates earlier this year, while Maine adopted a 100% target rather than a mandate. In addition, Maryland doubled its RPS mandate to 50%, even though the governor supported a more aggressive target. The newly enacted New York law mandates 70% renewable-generated electricity by 2030 and 100% carbon-free electricity by 2040.

California's 100% mandate was enacted in 2018 and that same year, Massachusetts, Connecticut and New Jersey expanded their RPS goals. In addition, many of these measures included specific carve-outs for solar and wind, provisions for battery storage and/or guidelines for electric vehicle pilot programs.

Several other jurisdictions also proposed RPS expansion bills during their 2019 legislative sessions, and these were either unsuccessful or have yet to be acted upon. Regulatory Research Associates, a group within S&P Global Market Intelligence, expects renewables expansion to be a continuing theme in future legislative sessions.

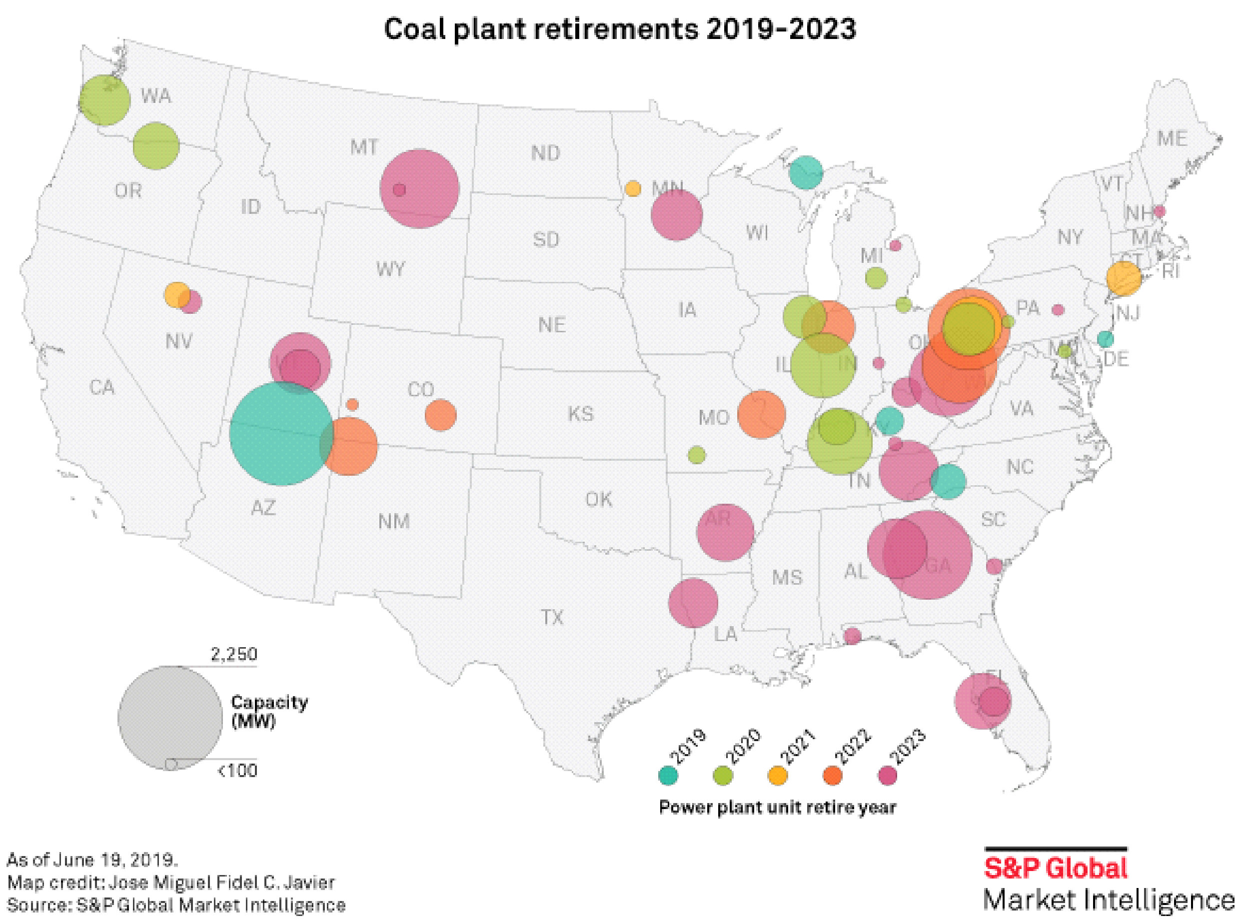
Separate from government-imposed renewable resource mandates and in response to investor and customer focus on ESG issues, many large U.S. corporations are committing to move to a more carbon-free emphasis in their generation procurement strategies.

Companies that committed to going 100% renewable range from small businesses with a comparatively small energy demand to large multinational corporations that consume millions of kilowatt-hours of electricity annually. Examples include Apple Corp., Coca Cola Inc., Facebook Inc., General Motors Corp., JP Morgan Chase & Co., The LEGO Group, Proctor & Gamble Corp. and Walmart Inc.

Similarly, spurred on by state mandates and also mindful of shareholders' and bondholders' desire for ESG-conscious options, utilities are investing in renewables at an accelerating pace. Declining costs have also played a role in keeping the momentum going despite the impending phase-out of investment and production tax credits.

Coal plant retirements

Against these headwinds, the United States' aging coal fleet continues to face major challenges despite federal efforts to prop up the industry. Just 15 years ago, coal accounted for over half of the U.S. generation portfolio. By 2018, that percentage had fallen to 27%. In 2017 and 2018 combined, 17 GW of coal-fired capacity was retired, and S&P Global Market Intelligence estimates that more than 28 GW will likely be retired in 2019 through 2023.



Regulatory responses to select recent plant closings are summarized below for illustrative purposes.

Earlier this month, PNM Resources Inc. subsidiary Public Service Co. of New Mexico, or PSNM, filed for approval to shut down the San Juan Plant in 2022 when an existing coal purchase agreement for the facility expires. PSNM contends that retrofitting the plant to meet more stringent state environmental regulations that take effect in 2023 would be more costly than shuttering the plant in 2022. PSNM proposes to securitize the undepreciated balance that is currently included in the company's rate base, roughly $283 million, plus other related costs.

The proposal apparently comports with legislation enacted earlier this year in New Mexico that permits the New Mexico Public Regulation Commission to approve such treatment. However, if past experience with stranded cost recovery is any indicator, it may not be as cut and dried as it might first appear.

While the most recent, this is not the case of first impression for this type of treatment. In 2013, the Michigan Public Service Commission authorized CMS Energy Corp. subsidiary Consumers Energy Co. to issue securitization bonds to finance the unrecovered book value of several coal-fired generating units that were to be retired prior to their planned 2025 shutdown date. Consumers had concluded that it would be uneconomic to bring these units into compliance with the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards; see the Michigan Commission Profile.

Similar legislation enacted in June 2019 in Colorado allows the state's investor-owned electric utilities to seek approval to securitize costs associated with the retirement of electric generation facilities. However, no petitions testing the new law have been filed as yet.

Other states have taken a different approach. In Oregon, in response to legislation requiring the elimination of coal generation by 2030, the Oregon Public Utility Commission authorized Portland General Electric Co. to accelerate depreciation of the Boardman plant and recover the increased depreciation expense through a tracker in order to facilitate the shutdown of the plant by 2020.

In Washington, Puget Sound Energy Inc.'s 2017 rate case decision called for modifications to the depreciation schedules for the Colstrip plant aimed at allowing units 1 and 2 to close by mid-2022 and units 3 and 4 to close by Dec. 31, 2027.

In Kentucky, American Electric Power Co. Inc. subsidiary Kentucky Power Co. uses a rider to recover the costs related to the 2015 retirement of the coal-fired Big Sandy Unit 2 plant, including a return on the investment. The Kentucky Public Service Commission authorized the rider as part of a rate case settlement adopted in 2015.

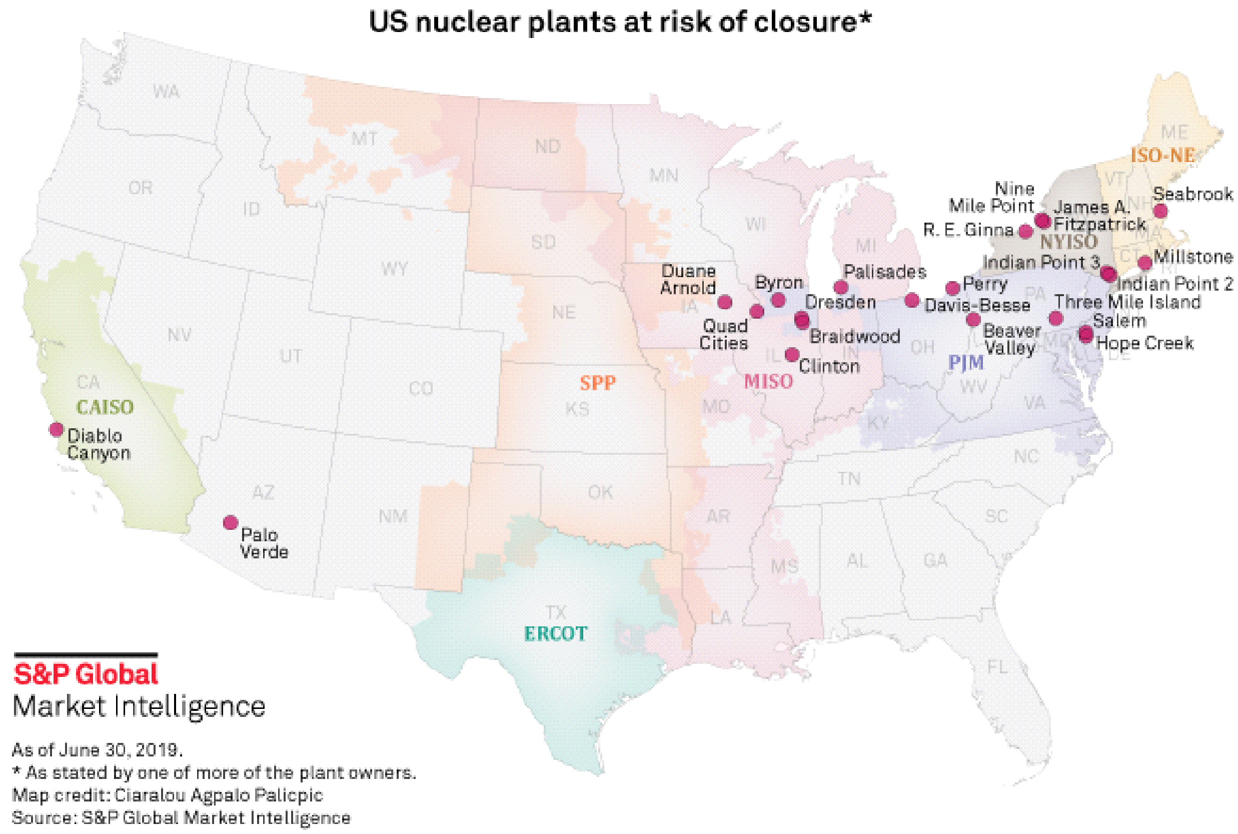
In a 2018 Texas rate case for American Electric Power subsidiary Southwestern Electric Power Co., the company had sought to include in rate base the undepreciated remaining book value of the Welsh 2 plant, which closed in 2016. Various parties opposed the proposal, largely on the grounds that the facility was no longer used and useful. The Public Utility Commission of Texas adopted a staff proposal to assign the undepreciated investment to a regulatory asset to be recovered over 24 years, the remaining useful life of Welsh 1, but with no return on the unamortized balance.

Finally, in a recently filed rate case, Duke Energy Corp. subsidiary Duke Energy Indiana LLC proposed to modify its depreciation schedules to reflect the shorter estimated service lives of three plants — R. Gallagher, Cayuga and Gibson — and recover the increased expense from ratepayers. An Indiana Utility Regulatory Commission decision in that case is expected in April 2020.

Nuclear plants at risk

While emissions-reduction requirements do not necessarily pose a threat for nuclear plants, low competitive power market prices and expanding renewables mandates are presenting challenges for these types of facilities. The conversation with respect to nuclear plants is somewhat more complicated than for the aforementioned coal plants, by virtue of the fact that most of the "at risk" nuclear units are merchant facilities.

Since 2013, seven plants totaling more than 6 GW have been shut down prematurely; six of the seven were unregulated or merchant plants. Consequently, the plant owners were largely unable to recoup any related stranded costs. Looking ahead, more than 30 nuclear plants, representing more than 34 GW of capacity, were at some time in the last few years referred to by the plant owners as "at risk" of closure.



Of these, all but two facilities — Diablo Canyon and Palo Verde — encompassing five units and roughly 6 GW, are merchant facilities. However, mechanisms are in place that are designed to forestall the premature closure of roughly 13 GW of the at-risk nuclear capacity.

Since 2016, four states — New York, Illinois, Connecticut and New Jersey — have adopted frameworks to prevent the early closure of legacy merchant nuclear plants.

In 2016, New York created a zero-emissions credit, or ZEC, framework to recognize the environmental attributes of nuclear generation. Under the plan, the state issues ZECs under contracts of up to 12 years to at-risk facilities, the continued operation of which represents a public necessity, as determined by the New York Public Service Commission. The transmission and distribution utilities are then required to purchase the ZECs from the plant owners in proportion to the load served. The cost is passed on to customers through the generation charge.

The PSC determined that the James A. FitzPatrick, R.E. Ginna/Ontario Sta. 13 and Nine Mile Point nuclear plants met the criteria; however, the Indian Point 2 and Indian Point 3 plants did not qualify.

A similar plan was enacted in Illinois that same year. The law required the Illinois Power Authority, which purchases power to meet standard offer service needs on behalf of the utilities, to enter into contracts with nuclear generation facilities in an amount equal to approximately 16% of the electricity delivered to end users in the state. The plants must be interconnected to either the PJM Interconnection or the Midcontinent ISO. Clinton Power Station and Units 1 and 2 of the Quad Cities power station were selected. However, Exelon Corp. warned that the Braidwood Generating Station, Byron Generating Station and Dresden nuclear plants are at risk of early retirement after most of the capacity failed to clear a subsequent PJM capacity auction. Approval to participate in the Illinois ZECs plan was a one-and-done proposition, so additional legislation would likely be required to expand the program to accommodate any of these other facilities.

Connecticut took a different approach. Legislation enacted in 2017 permitted nuclear plants deemed to be at risk of premature closure to compete in Connecticut's RPS solicitation if the state Department of Energy and Environmental Protection and the Connecticut Public Utilities Regulatory Authority deemed it to be in the public interest. The total annual energy output of the selected proposals is limited to 12 million MWh, and the terms of the agreements must be between three and 10 years.

In December 2018, the Connecticut regulator determined that Millstone, operated by Dominion Energy Inc., and Seabrook, operated by NextEra Energy Inc., qualified for an at-risk designation, and contracts have since been approved for those facilities.

New Jersey took an approach similar to New York and Illinois, and in May 2018 adopted a ZEC framework. Eligibility to receive ZECs is determined by the New Jersey Board of Public Utilities for a three-year period. Each investor-owned electric utility in the state is required to purchase ZECs on a monthly basis from each plant selected, with the related costs recovered by the utilities through nonbypassable charges on customers' bills. In April 2019, the BPU determined that the Public Service Enterprise Group Inc.'s Hope Creek and Salem nuclear plants — also owned by Exelon — qualified under the program.

Other states have discussed similar programs but have not pulled the trigger. As of July 18, Ohio and Pennsylvania were considering nuclear-supportive legislation. The Ohio bill, which would also offer some support to in-state coal facilities, provides for credits for certain types of generation facilities, similar to the ZEC concept. The Ohio bill was signed July 23 as this article was going to publication. The Pennsylvania bill would, like the Connecticut plan, include nuclear generation as a class of renewable resources.

During the 2019 legislative session, Maryland considered a bill that would have allowed nuclear plants to be considered renewable resources. However, a watered-down version of the bill was ultimately enacted calling for a study commission to review the issue.

In Minnesota, where electric industry restructuring has not been implemented, legislation was discussed in 2018 that would have categorized nuclear as a renewable resource but failed to be enacted. Interestingly, a proposed 2019 bill specifically excluded nuclear from the definition of renewables.

The issue of support for legacy generation facilities is likely to remain a controversial one, particularly in jurisdictions where retail choice has been introduced.

The New York and Illinois plans were appealed by independent power producers who argued that the programs were anti-competitive and impinged on the Federal Energy Regulatory Commission's authority. The state rulings were upheld in federal circuit courts, and the U.S. Supreme Court declined to hear further appeals.

Nevertheless, the New Jersey Division of Rate Counsel, which vocally opposed the state's ZEC legislation, has appealed the BPU's decision with respect to awarding ZECs to the selected plants. The Rate Counsel fought against the legislation on the grounds that the "bailout" was too costly for ratepayers, but it has appealed the BPU ruling stating that the plants in question failed to meet the statutory criteria. It remains to be seen how this will play out in the state courts.

Key takeaways

* Stranded costs are not a new issue, and how this issue was addressed in the past can provide insight into how stranded assets may be treated going forward, with the caveat that today's situation is complicated by the implementation of retail choice for generation.

* Further, given the dramatic shifts in resource mix and demands for decentralized options, nongeneration assets may also become "stranded" in the future.

* Remedies are likely to be controversial as policymakers strive to balance the needs of ratepayers and shareholders while maintaining reliability, universal service, and security of the grid and customer information.

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Article amended at 3:05 p.m. ET on July 23, 2019, to note that the Ohio bill previously described as pending had been signed.

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