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Nuclear could steal market share from gas

ANALYSIS The long-term prospects for the nuclear power industry are not rosy, but in the near term nuclear power could steal market share away from gas-fired generation.

Last year was a record year for the nuclear power industry, with four reactors were taken out of service, shrinking the fleet to 100 reactors from 104 and prompting speculation about which plants could be the next to retire.

The nuclear power industry is also poised to set a record this year by having less downtime for refueling outages. Between January and June, refueling outages will be 2,600 MW lower than last year's refuelings and between September and December they will be 1,300 MW lower, according to a March 19 presentation by analysts at IIR Energy, based in Sugar Land, Texas.

In fact Nuclear Energy Institute data shows a declining trend in

(continued on page 16)

DOJ, FERC say New Jersey law is pre-empted

MARKETS New Jersey's law directing the construction of 2,000 MW of gas-fired generation directly affects wholesale power prices and therefore is pre-empted by the Federal Power Act, the Department of Justice and the Federal Energy Regulatory Commission told a court.

"The US and the commission are of the view that the New Jersey Act is pre-empted because of its price-suppressive and distorting effect on the PJM [Interconnections]'s wholesale capacity market prices," FERC and DOJ said in a brief filed late Thursday with the US Court of Appeals for the Third Circuit.

The Federal Power Act gives FERC jurisdiction to determine whether rates tied to the transmission or sale of electricity are just and reasonable, and in a regional capacity market such as PJM's, it

(continued on page 17)

NYISO mulling scarcity pricing changes

MARKETS Under a "comprehensive review of scarcity and shortage pricing" to be completed this summer, the New York Independent System Operator is considering improvements to its scarcity pricing rule to avoid discouraging electricity imports and to reduce the potential for higher day-ahead margin assurance payments for generators.

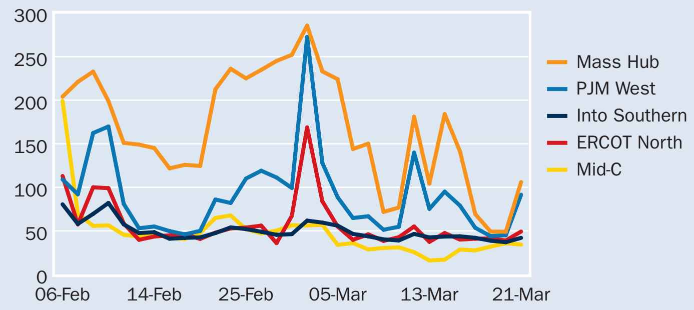
The review follows the use of demand response and scarcity pricing rules, including during a heat wave last summer, with subsequent comments from NYISO stakeholders.

NYISO "expects to complete its review of shortage and scarcity pricing with input from its stakeholders by the end of June," NYISO spokesman Ken Klapp said.

The ISO's deliberations about scarcity pricing under its emergency demand response and special case resources programs

(continued on page 17)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Mar 22 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	59.16	61.31	35.50	36.77
NYISO	39.77	68.10	35.25	43.99
PJM	33.58	42.50	29.12	36.65
MISO	36.79	48.20	25.45	32.33
ERCOT	42.56	46.61	28.06	28.67
SPP	37.97	44.28	17.34	27.70
CAISO	44.25	45.99	40.19	41.56

Note: Lows and highs for each ISO are for various hubs and zones. A full listing of average LMPs are availible for the hubs and zones inside this issue.

Day-ahead bilateral indexes and spark spreads for Mar 24

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	106.00	12398	46.15	37.60	20.50	3.40	-22.25
N.Y. Zone-A	74.75	16244	42.54	37.94	28.73	19.53	5.73
PJM/MISO							
PJM West	91.50	21768	62.08	57.87	49.47	41.06	28.45
Indiana Hub	59.00	12826	26.80	22.20	13.00	3.80	-10.00
Southeast & Central							
Southern, Into	42.00	9605	11.39	7.02	-1.73	-10.47	-23.59
ERCOT, North	49.25	11507	19.29	15.01	6.45	-2.11	-14.95
West							
Mid-C	34.29	7641	2.88	-1.61	-10.59	-19.56	-33.02
SP15	51.00	11148	18.98	14.40	5.25	-3.90	-17.63

Note: All indexes are on-peak. Spark spreads are reported in ($) and Marginal heat rates in (Btu/kWh). A full listing of bilateral indexes and marginal heat rates are inside this issue.

Inside this Issue

obligation CRRs. Clearing prices for this path ranged from about $2,701/MW for on-peak weekday CRR options to about $454/MW for off-peak CRR obligations.

On-peak weekday CRR options in ERCOT's South zone from the South Hub to unit 10 of the Silas Ray power plant in Brownsville in Cameron County in southern Texas (SIL_SILAS_10) had the highest clearing price in this month's auction at about $6,459/MW.

The largest negative clearing price in this month's auction — about negative $5,765/MW — was for on-peak weekday CRR obligations from unit 10 of the Silas Ray power plant to unit 6 of the Trinidad power plant in Henderson County in ERCOT's North zone (TRSES_UNIT6).

Of the 64 varieties of CRRs in this auction with clearing prices above $3,000/MW or below negative $3,000/MW, a total of 23 had their source and sink points in ERCOT's West zone while 21 had their source and sink points in ERCOT's South zone. Of the 18 types of CRRs with clearing prices above $4,000 or below negative $4,000, a total of 12 had their source and sink points in the South zone.

— Juliana Brint

Nuclear plants could steal market share

...from page 1

refueling outages with 65 recorded in 2011, 63 in 2012, and 51 in 2013.

Fewer refuelings lead to higher availability for the nuclear fleet as a whole and that has the potential to decrease power sector demand for natural gas by up to 600 MMcf/day, IIR analysts estimate. If the effect of refueling outages is combined with other planned outages the bight is even bigger, as much as 1.3 Bcf/day, according to IIR.

While she sees value in IIR's data, Teri Viswanath, director of natural gas strategy at BNP Paribas, which hosted the presentation by IIR, has a more nuanced, regional view of upcoming refueling activity.

If there are fewer nuclear plants offline, gas demand will decline, but Viswanath expects 1 GW more of nuclear capacity in the Electric Reliability Council of Texas region to be offline for refueling over last year and almost 3 GW more to be offline in the Southeast. She thinks most of the effect from fewer refuelings could be seen in the Midwest where coal, and not gas, could be more affected. Overall she says incremental power demand for gas could rise by 1 Bcf/day during the spring (April-May) refueling season.

But while fewer refuelings might be bad news for gas generators, it is not necessarily good news for nuclear operators. "That is the quandary," Viswanath said. With power prices in the $35/MWh range, many nuclear plant owners are looking at significant losses, she said.

The quandary is that in wholesale markets nuclear power has trouble competing with cheap natural gas. While nuclear operators have relatively low fuel prices, they face relatively high overall costs. According to NEI, nuclear plant operating costs have risen to $44.17/MWh in 2012 from $27.91/MWh in 2002.

That was a driving factor behind the unprecedented level of nuclear plant retirements announced last year. Dominion and Entergy both cited economics and market conditions when they announced plans to close their Kewaunee and Vermont Yankee plants. Two other nuclear plants that closed last year, San Onofre and Crystal River, were the result of complications from repairs, but also involved economics, in the form of the high cost of the repairs that would have been needed to keep them open.

The bad news for nuclear operators, and for the nuclear fleet as a whole, is that those economics are not likely to change.

"2013 was not an anomaly," Brock Ramey, North American research manager for power at IIR, said. IIR's presentation included a list of 13 reactors totaling 11,630 MW that it considers "at risk." The list includes several plants that have been mentioned for possible retirement by other analysts, such as Indian Point, Fitzpatrick, Ginna and Nine Mile Point in New York, as well as the Diablo Canyon station in California, Fort Calhoun in Nebraska, Palisades in Michigan, Clinton in Illinois, Davis-Besse in Ohio, and Seabrook in New Hampshire.

Notably not all those "at risk" plants are merchant, showing that nuclear plants face challenges in addition to the economics of wholesale markets. Facilities like Diablo Canyon face permitting issues while the Fort Calhoun plant has been suffering from poor performance, according to IIR.

Nor are all 11.6 GW of those plants going to retire, Greg Elliott, product manager for power at IIR, said. He noted, for instance, that five of the 13 reactors on the list are in New York and that the state would be hard pressed to keep the lights on if all those plants were to close.

The likely outcome is that the US nuclear fleet is diminishing. "I firmly believe the nuclear fleet is going to shrink," John Best, vice president at IIR, said in an interview.

Even if only half of the 11.6 GW retires, it is still not enough to outpace the 5.6 GW of reactors that are under construction and expected to come online between 2015 and 2019. Beyond that, it is unlikely that another nuclear plant will start construction before 2020, Ramey said.

Meanwhile nuclear uprates, which have been a steady source of capacity growth for the nuclear fleet, are slowing. "Uprates have ground to a halt," Best said. Most of that slowdown is the result of a combination of regulatory uncertainty and challenging economics.

An uprate can cost anywhere between $150 million and $500 million for a 15% to 20% increase. Faced with those costs, a plant owner has to weigh a possible uprate against an investment in a gas turbine that would yield a modern, new plant without the same level of regulatory hurdles. "That is something a lot of owners are looking at," Ramey said.

The bright spot for the nuclear industry is that the decrease in capex for uprates is contributing to the first decline in nuclear plant costs since 2007, NEI said. Average nuclear plant costs fell to $41/MWh in 2013, a 9% drop from 2012 costs, NEI noted.

That could help nuclear operators to compete in the wholesale market, but the owners of those plants also want to see higher capacity prices. They are quick to point out that nuclear plants have several attributes for which they say they are not adequately compensated, such as reliability, steady fuel supplies and stable fuel prices.

Those attributes came to the fore during the extreme cold weather this winter, and several nuclear owners are now using that experience to lobby for changes in how wholesale markets compensate generators.

The timing might prove fortuitous. In June the Environmental Protection Agency is due to release its New Source Performance Standards for curbing carbon dioxide emissions. Those regulations are expected to give states latitude in setting their own emissions levels.

As UBS analyst Julien Dumoulin-Smith pointed out in a recent report, the threat of carbon regulations could scare states into "saving the nukes." And, he noted, states using 2014-15 to establish an emissions baseline would not want to see zero emission nuclear power subsequently removed from the mix. That could give nuclear owners bargaining power to win market concessions.

Another option that nuclear owners could be looking at, particularly in markets such as New England and New York that could be looking at a new winter peak season for power, would be to mothball a nuclear plant rather than retire it.

That could be a particularly attractive option for owners of plants that already have a 20-year extension of their original 40-year operating licenses. They might "keep that in their back pocket" while they monitor market conditions, especially during the winter, Ramey said.

— Peter Maloney

DOJ, FERC say New Jersey law pre-empted ...from page 1

has the exclusive jurisdiction over capacity prices, the brief said.

Generators and others challenged the New Jersey law in federal district court. When the court ruled that the Federal Power Act pre-empts the state law, the state appealed. Neither DOJ nor FERC were parties to the federal court proceedings, but the appeals court asked them to weigh in.

The law directly affects wholesale rates because of its requirement that the companies selected to build new generation bid into and clear PJM's capacity auction, the brief said. That action lowers the auction clearing price, "a practice unmistakably affecting rates," DOJ and FERC said.

The New Jersey law guarantees payments "to or from" the generators to make up the difference between the market clearing price and the amount specified in the state-mandated contracts with utilities. As a result, the subsidy is explicitly and directly tied to "and thereby directly affecting" wholesale rates, the brief said.

Because the subsidies are tied directly to the market-clearing price, the generators submitted below-cost and market distorting bids, directly affecting the auction's resulting wholesale capacity rate, according to the brief. The artificial, below-cost bids set a lower wholesale rate, undermining the commission's ability to ensure just and reasonable rates, it said.

"Those aspects of the New Jersey Act – which might benefit select generation resources in New Jersey, but to the detriment of other resources in other PJM states facing artificially lower prices for their capacity – intrude on the exclusive jurisdiction of the commission over prices affecting wholesale rates in interstate commerce and is preempted," the brief said.

New Jersey's jurisdiction over generation plants is preserved, DOJ and FERC said. The New Jersey law is not pre-empted as long as the resources it incentivizes do not directly interfere with the regional wholesale market. States may take actions that would indirectly affect capacity markets without encroaching on FERC's exclusive jurisdiction over setting the price for capacity, the brief said.

"FERC's concern is whether an action is aimed at specifically affecting the wholesale market, as opposed to a state policy that has the ancillary effect on the market," Paul Patterson, a analyst with Glenrock Associates, said Friday in an interview.

Patterson cited state regulations requiring demand response, energy efficiency and the development of renewable resources. "While those regulations do affect the capacity market, they are not directly aimed at affecting it like the New Jersey law," he said.

The view of DOJ and FERC is narrowly focused on the purpose of the New Jersey legislation to affect capacity prices, Patterson said.

Their view is not a surprise, said Glen Thomas, president of the generator group PJM Power Providers. "There are many things states can do, but setting wholesale capacity prices is not one of them," he said.

— Mary Powers

NYISO mulling scarcity pricing changes ...from page 1

follows its implementation of scarcity pricing rules approved on July 8, 2013, by the Federal Energy Regulatory Commission (ER13-909). FERC required NYISO to report on the effectiveness of the scarcity pricing rules, which the grid operator did on October 31.

The report detailed a July 15-19 heat wave that required the deployment of about 1,824 MW of demand response that ultimately received the greater of $500/MWh or the locational marginal price for load reductions. The demand response programs have higher enrollment during the summer, with winter enrollment for the two programs typically about 50% of summer enrollment, Kkapp said.

Although the scarcity pricing rules worked well during the July 2013 heat wave, NYISO informed FERC that it "will be looking at