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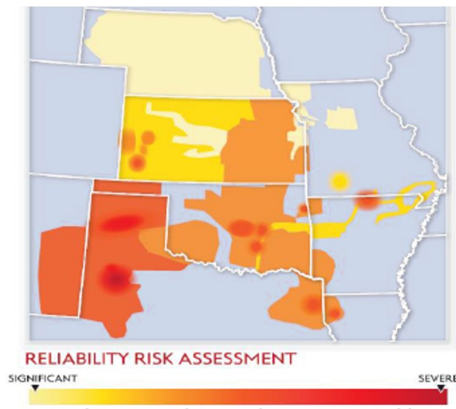
SPP: $45/ton Carbon Adder and More Wind Could Meet CO_2 Rule

By Chris O'Malley and Rich Heidorn Jr.

SPP could meet the Environmental Protection Agency's 30% carbon dioxide reduction target by 2030 through a $45/ton carbon adder and 7.8 GW of additional generation, most of it wind, according to a report issued last week by the RTO.

The analysis, the RTO's second on the potential impacts of EPA's Clean Power Plan, estimates the cost of those measures at $2.9 billion per year, not including additional transmission or gas pipelines that will be needed.

SPP's first study, released in October, concluded that EPA's implementation timeline — particularly its 2020 interim goals — did not allow enough time to build needed generation and transmission to replace coal plant retirements and deliver wind power to population centers. It predicted SPP's transmission system could face severe overloads, increasing the potential for cascading outages.



Areas in yellow, orange and red are at risk of power shortages due to expected generation retirements under EPA's Clean Power Plan, according to an SPP analysis.

"This second analysis does not alter our earlier conclusion that additional infrastructure — and time — is needed to meet the CPP's proposed CO_2 emission goals," Lanny Nickell, vice president of engineering, said in a statement.

During a series of technical conferences convened by the Federal Energy Regulatory Commission, and at meetings with state

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MISO-PJM Cross-Border Projects Still Languishing, NIPSCO Says

By Chris O'Malley

Northern Indiana Public Service Co., which filed a complaint in 2013 over its frustrations with MISO and PJM's interregional planning process, says nothing much has changed since then.

"Close to one and one-half years have passed since NIPSCO filed its complaint in this docket, and the same pattern of a great deal of process with no results appears to be holding," the utility said in a March 31 filing with the Federal Energy Regulatory Commission.

More than a decade after the MISO-PJM seam was formed, no cross-border projects have been approved and built, while hundreds of millions of dollars in market-to-market payments have been made, NIPSCO said, "including approximately $500 million since 2008."

A MISO member, NIPSCO is located between two PJM transmission zones, Commonwealth Edison to the west and American Electric Power to the east.

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PJM Responds to FERC Queries on Capacity Performance, Requests Approval

By Suzanne Herel

PJM on Friday filed a 37-page response to questions raised by the Federal Energy Regulatory Commission about its Capacity Performance proposal and requested that the board accept the plan effective April 1 so that it may implement the changes in the Base Residual Auction scheduled for next month.

"Despite [their] success in retaining and attracting sufficient capacity to ensure resource adequacy requirements are met, the capacity markets are failing to incentivize adequate generator performance. Resources in PJM have not performed as expected," PJM said.

"Simply, [the Reliability Pricing Model's] current capacity market performance incentives and requirements are weak, and therefore require immediate reform," PJM said, noting that the auction secures commitments on a three-year, going-forward basis.

"If PJM deferred these changes to the following BRA, held in May 2016 for the delivery year that starts on June 1, 2019, it would mean that the PJM region would let *five more* winters pass after 2014 without implementing a full remedy to the manifestly deficient performance requirements in the current rules," it said.

While the RTO had 30 days to respond to

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regulators, EPA officials suggested the final rule due this summer may relax the 2020 goals, which have been widely criticized as unworkable. (See EPA on Carbon Rule: We're Listening.)

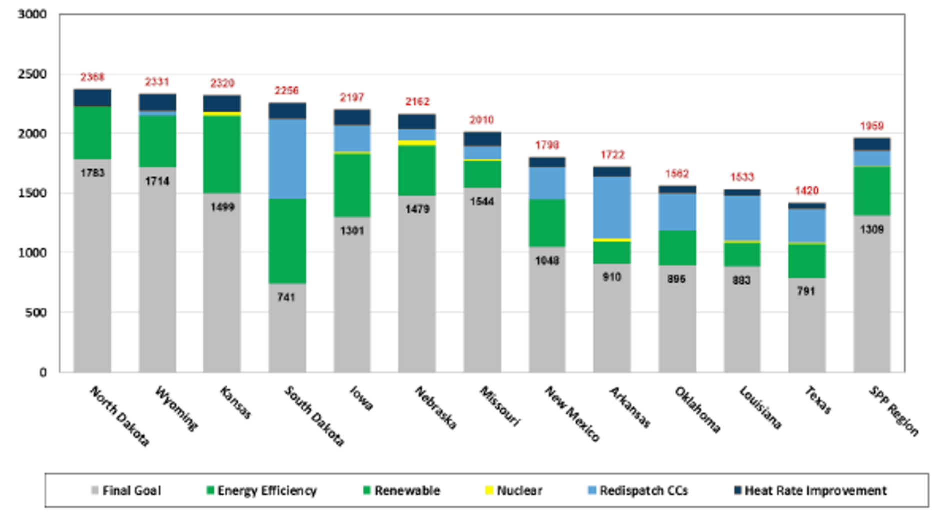
Methodology

SPP said its analysis found that the region could meet the EPA goal with a carbon adder — essentially a tax on a unit's carbon emissions — of $60/ton of carbon emissions. But it said an adder cost of $30-$45 per ton would be most cost-effective.

The report's conclusions are based on a $45/ton adder and the addition of 5.6 GW of wind and 1.2 GW of natural gas generation above that currently planned.

The $2.9 billion in annual costs is the result of $600 million in increased annual energy costs and $13.3 billion in capital spending. The study did not evaluate infrastructure needs and thus did not include costs of transmission or gas pipeline that would be needed.

The study assumed a 70% capacity factor for combined-cycle gas generators and 47% for new wind. The added wind generation would allow that resource to meet 25% of the non-coincident peak-load obligations in the region. SPP's minimum 12% capacity margin was preserved in each load zone.



State and SPP CO_2 emission rate limits. (Source: SPP)

Unduly Pessimistic

The tone of SPP's second analysis is less gloomy than that of the first, which warned of the possibility of rolling blackouts. But critics said the new report is still unduly pessimistic.

The American Wind Energy Association said SPP's analysis overestimates compliance costs because it "arbitrarily" limited the region's options.

Michael Goggin, AWEA's senior director of research, said SPP's assumption for the cost

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SPP Market Monitor Protests Make-Whole Promise for Gas Units

By Rich Heidorn Jr.

SPP's Market Monitoring Unit asked the Federal Energy Regulatory Commission last week to reject a proposal that would bar the RTO from canceling commitments of gas-fired generators if they are not needed.

SPP's proposal would result in "an inefficient transfer of gas market risks to SPP's load," wrote Catherine Tyler Mooney, the MMU's manager of market analytics (ER15-1293). "… This commitment may impose uneconomic production on the market, impacting market prices, uplift, congestion, transmission congestion rights payments or market-to-market settlements."

At issue is SPP's March 16 proposal to codify its historical practice of not de-committing generators committed out of its multi-day reliability assessment during emergency operations. The Tariff change would bar SPP from decommitting such units unless they presented a reliability risk.

SPP proposed the change after some gas-fired generators in PJM complained that they suffered "stranded gas" losses in 2014 when they bought fuel at high prices in response to transmission operators' directions that were not needed by the market later. (See PJM Backs Duke's $9.8M 'Stranded Gas' Claim.)

SPP said it filed the Tariff revisions in response to "stakeholders' request for clarity on whether and how resources may be committed" under its multi-day reliability assessment if SPP has implemented conservative operations under its emergency operating plan. The proposal was approved by the RTO's Members Committee and Board of Directors in January.

The MMU said the proposed change was problematic for several reasons. "First, it may be difficult for SPP to verify the legitimacy of unused fuel cost claims. Second, generator operators are in the best position to effectively minimize fuel costs."

The MMU said that SPP should have the ability to reevaluate its need for generation during emergencies — if, for example, weather forecasts change.

"Avoidable adverse consequences should not be imposed on the market to lessen the predetermined cost exposure of individual generators," the MMU said. "It is not a cost-minimizing market outcome. If SPP staff, its members and the commission believe that an uplift payment for unused fuel is necessary to preserve system reliability during emergencies, SPP should pursue that particular issue."

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of new wind generation is about 40% higher than current wind in the region, a nearly $1 billion difference. "Those costs would be even lower if SPP accounted for how wind energy costs continue to fall drastically, dropping by more than 50% over the last five years," he wrote in a blog post.

Goggin said SPP's analysis also did not include energy efficiency as a compliance option and assumed almost no new gas generation would be built.

"SPP's study essentially examines what would happen if the region tried to comply with one arm tied behind its back," he said. "If the region had been allowed to fully utilize its abundant and low-cost resources of wind, natural gas, and energy efficiency, the cost of achieving the Clean Power Plan would have been far lower."

SPP acknowledged it did not analyze each of the EPA's proposed "building blocks." Unlike the RTO's Integrated Transmission Plan, the study also did not consider economic interchange with other regions. The RTO said it made this choice to minimize "the uncertainty associated with trying to determine how SPP's neighbors will operate under their own compliance with the CPP."

Stakeholders in SPP and MISO told a FERC technical conference last month they are developing the framework for a cap-and-trade interstate trading platform for carbon. (See *MISO, SPP Stakeholders Developing Trading Plan to Comply with EPA Carbon Rules*).

Indicative, Not Definitive

In an interview, Nickell said the AWEA critique failed to "recognize that the study was meant to be indicative as opposed to definitive." Nickell said some potential compliance options were excluded to provide an apples-to-apples comparison for a third, state-by-state analysis, which is expected in early June.

"This second analysis does not alter our earlier conclusion that additional infrastructure — and time — is needed to meet the CPP's proposed CO_2 emission goals."

Lanny Nickell, SPP Vice President of Engineering

"This isn't the only way to solve the problem," he acknowledged. "Clearly [energy efficiency] could reduce costs. It's a matter of what could be done."

While the study assumes only 1.2 GW of incremental gas-fired generation, that is in addition to 22 GW of new gas capacity already planned, he added.

Retirements

SPP's scenario assumed about 2.2 GW of coal retirements "incremental to those retirements already planned," based on those generators running below a 30% capacity factor after adding a $45/ton adder.

As much as 13.9 GW of generation could be at risk of retirement in addition to what is included in SPP's current transmission planning models, SPP said.

"This assumption may be conservative considering that SPP's analysis indicates nearly all existing coal-fired generation in the region would operate above 80% capacity factor without a carbon cost adder but approximately 12,200 MW of coal-fired generation would operate below 80% capacity factor with a $45/ton cost adder."

The analysis does not take into account transmission constraints or interchange with adjacent pools, SPP said.

AWEA also criticized the report's claim that 13.9 GW of coal is "at risk" of retirement.

"SPP gets to the extremely unrealistic 13.9 GW number by considering coal plants 'at risk' for retirement if they fall below an 80% capacity factor. An 80% capacity factor is an extremely high and unrealistic threshold for considering a plant at risk of retirement; in fact, the national average coal plant capacity factor is currently 60%. Almost all of SPP's 'at risk' coal plants would actually just be operating at average capacity factors."

From Crisis to Inevitability

Late last year, SPP and MISO warned of a reliability crisis if the Clean Power Plan isn't eased to account for up to 134 GW of generation retirements by 2020, most of them coal-fired units. (See *MISO, SPP: EPA Clean Power Plan Threatens Reliability*.)

SPP's first study assumed new generation was added without additional transmission infrastructure. The model showed that portions of the system in the Texas panhandle, western Kansas and northern Arkansas "were so severely overloaded that cascading outages and voltage collapse would occur and would result in violations of [North American Electric Reliability Corp.] reliability standards," SPP CEO Nick Brown said in his comments to EPA.

But the initial alarm about the Clean Power Plan has given way to compliance strategy contemplation. In addition to the third study that will analyze the cost of state-by-state compliance, the RTO is beginning work on a transmission planning study. That analysis is targeted for January 2017, Nickell said.

"SPP's study essentially examines what would happen if the region tried to comply with one arm tied behind its back."

Michael Goggin, AWEA

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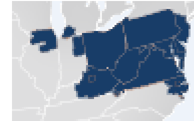

Deadline Looms for Decisions in Exelon-Pepco Deal

Delaware Regulators Near Settlement; More Join Opposition in DC

By Suzanne Herel

Supporters and critics of Exelon's proposed $6.8 billion takeover of Pepco Holdings Inc. are churning out newspaper opinion pieces, resolutions and public relations campaigns as the last holdouts to the deal approach deadlines to render decisions.

Delaware regulators last week agreed on a final settlement but will wait to sign it until deals have been finalized with Maryland and D.C.

Evidentiary hearings were scheduled to end last week in D.C., but two more days of testimony were added for April 20-21. The Public Service Commission will close the record on May 13. (See CEO Crane to DC PSC: Exelon Committed to Jobs, Ratepayers.)

In Maryland, hearings are set for Wednesday, Thursday and, if necessary, Friday. The PSC has a deadline of May 8 to reach a decision.

The acquisition already has been approved by the Federal Energy Regulatory Commission, the New Jersey Board of Public Utilities and the Virginia State Corporation Commission.

Exelon has promised all jurisdictions equivalent concessions, the bulk of which address customer benefits, workforce retention and commitments to energy efficiency. It also conceded items of particular interest to some jurisdictions, such as recreational trails in Maryland and a feasibility study of wind generation in Delaware's southern counties.

Pepco Holdings Inc. CEO Joseph Rigby testifies before D.C. Public Service Commission. (Source: D.C. PSC)

Delaware PSC on Board

Under the terms of the settlement outlined before the Delaware Public Service Commission last week, electricity users will share a one-time credit this summer totaling $40 million instead of a larger payout that would have been distributed over 10 years. Exelon also committed to spend $2 million for a low-income energy efficiency plan for PHI's Delmarva Power & Light customers.

One intervener initially skeptical of the deal, University of Delaware professor Jeremy Firestone, withdrew his opposition at last week's hearing, saying he was pleased to have helped negotiate the lump sum credit and the study of wind generation in Kent and Sussex counties.

PJM's Independent Market Monitor, represented at the hearing by General Counsel Jeffrey Mayes, said the merger should be conditioned on several measures designed to ensure competition, including a promise to remain in the RTO indefinitely and to make property paid for by ratepayers available to competitive transmission developers. The suggestions, however, gained no traction among the commissioners.

Although the commission did not vote on the agreement, none of the commissioners expressed opposition.

State Rep. John Kowalko, who did not act in time to become an intervener, was the lone voice of dissent during public comments at the hearing, saying the interests of Delaware's 250,000 residential ratepayers will be lost among the total of 9.6 million customers affected by the acquisition. "We will be the proverbial flea on the elephant's back," he said.

Opposition Grows in DC

The deal is facing stiff opposition in D.C., where nearly half of the District's Advisory Neighborhood Commissions last week passed measures against the takeover, including every ANC in Ward 4, home to Mayor Muriel Bowser. None of the groups has come out in support of the deal.

"Some of D.C.'s electricity consumers have long suffered from poor reliability, and allowing our power decisions to be made by an out-of-state energy conglomerate with a sizeable roster of high-priced nuclear power plants would not be in our community's best interest," Douglass Sloan, commissioner of ANC 4B09, said in a statement released by Power DC, a coalition of electricity customers concerned about rates, reliability, renewable energy and local control.

Three of the 12 members of the D.C. Council — Mary Cheh, Elissa Silverman and Charles Allen — filed a letter with the PSC opposing the merger. The Office of People's Counsel is also advising against approval.

Exelon has fared better in Maryland, where two key counties — Montgomery and Prince George's — agreed to support the acquisition in return for promises to fund customer bill credits, grid reliability improvements, renewable energy projects, energy efficiency programs and help for low-income consumers. (See Exelon, Pepco Ink Deal with Md. Counties, but Critics Stand Firm.)

However, the Montgomery County Council split from County Executive Ike Leggett and unanimously passed a resolution saying that the settlement "does not adequately address the overarching issues that have led the state, the Office of People's Counsel, the environmental community and other public interest organizations to maintain that the merger is contrary to the public interest."

The acquisition also is opposed by state Attorney General Brian Frosh.

If the deal is approved, it will create the Mid-Atlantic's largest electric and gas utility.

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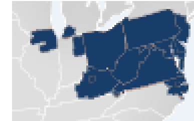

Stakeholders Skeptical of PJM Proposal for 'Historic' Capacity Transfer Rights

By Suzanne Herel

VALLEY FORGE, Pa. — Stakeholders last week continued their debate over PJM's proposal to create "historic" capacity transfer rights for some load-serving entities, with the Independent Market Monitor cautioning the Market Implementation Committee that the new Tariff language would constitute a "fundamental change."

The proposal resulted from a problem statement approved by the MIC in December to review modeling practices that the RTO said may be shortchanging loads with transmission agreements that pre-date the RTO's capacity market.

The changes would allow market participants to use generation resources outside of their locational deliverability areas (LDA) to meet their internal resource requirements if that external capacity agreement was in place before June 1, 2007, when PJM implemented its Reliability Pricing Model. Previously, there was no locational differentiation made among capacity resources.

The proposal would address the situation faced by the Illinois Municipal Electric Agency, which last year won a federal waiver to allow it to use capacity resources outside of the Commonwealth Edison LDA to meet its internal resource requirement in serving its Naperville, Ill., load.

The Federal Energy Regulatory Commission granted IMEA a waiver for the 2017/18 delivery year after the ComEd LDA last year was modeled for the first time with a separate variable resource requirement curve (ER14-1681).

In January, however, the commission rejected IMEA's request to continue use of the waiver for future delivery years, saying it had enough time to prepare to meet its internal resource requirement (ER14-1681-001). The commission also rejected a specific waiver request for the 2018/2019 delivery year (ER15-834). (See *Illinois Regulators, IMM Line Up Against IMEA Capacity Waiver Request*.)

PJM estimates 1,037 MW of historic external resources would qualify under its proposal: 122 MW in the DOM zone, 533 in COMED, 261 in AEP and 121 in DAY.

"This isn't a piddling amount of megawatts," GT Power Group's Dave Pratzon said.

One stakeholder, who declined to be identified by name, said the rule change would be fair if it protects the property rights of load-serving entities that had funded transmission upgrades that increased the capacity emergency transfer limit (CETL) into their region.

But he said it may be "inequitable" if it also covers those whose only claim is a firm transmission reservation that predates RPM. Others observed the change would give such LSEs a preference over their neighbors for available transmission capacity.

Pratzon said he was concerned that PJM would be unable to set a "bright line" to distinguish between entities that have legitimate claims from those that don't.

"It does seem to be creating a preferential set of rights for a certain group of people. I wouldn't want us to set something up where in effect we're giving people a second bite of the apple for certain decisions they made in RPM that they wish they hadn't made," he said. "I want to make sure we're not putting ourselves on a slippery slope to other requests for special treatment."

Mark Hanson, an economic analyst for the Illinois Commerce Commission, said the proposal goes too far. "It seems like maybe [entities such as IMEA have] gone from being too much at risk to being immunized from risk," he said.

Market Monitor Joe Bowring said the change "represents a very substantial, fundamental change to the way [capacity transfer rights] are allocated within LDAs."

Stu Bresler, PJM vice president of market operations, said the proposal would apply to a "well-defined subset" of LSEs. "It could never grow. We'd never have a new one," he said.

Bresler said PJM will provide additional information on its proposal at next month's MIC meeting.

PJM Operating Committee Briefs

PJM: New Rule on Lost Opportunity Costs Would Exclude 1/5 CTs

About 20% of PJM's combustion turbines, representing 30% of its CT capacity, would be barred from receiving lost opportunity costs under a rule change awaiting a shareholder vote, PJM officials told the OC last week.

Adam Keech, director of wholesale market operations, said PJM conducted the analysis after the Markets and Reliability Committee last month tabled voting on the proposal.

The delay came after some stakeholders complained that the changes — which would generally limit lost opportunity costs to units with start-up and notification times of no more than two hours and minimum run-times of two hours or less — were too restrictive. (See *PJM Tables Rule Change on CT LOCs*.)

Keech said that if the minimum run-time threshold were increased to four hours from two, only 10% of CT units and capacity would be excluded from lost opportunity costs.

PJM officials told the OC they had no operational concerns about the changes.

One generation operator, who declined to be quoted by name, said the new rules would create "perverse incentives" for generator operators, resulting in some units running under self-schedules for an additional hour after the two-hour limit. "I will submit a schedule that meets your payment parameters, but on operations I need to do what I need to do," he said.

"Instead of using a carrot approach, you're using a stick approach," he added.

Keech said that the change, which is supported by PJM and the Independent Market Monitor, was intended to eliminate incentives at odds with PJM's needs. Under the current rules, he said, "you get paid more if you don't run [in real-time] than if you do."

Louis Slade, a senior policy manager for Dominion Resources, questioned whether PJM's data would be accurate in the future, saying most new CTs are 150 MW or larger and have minimum run times of longer than two hours. "Two hours potentially puts a lot

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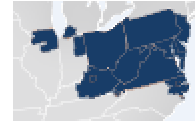

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of the newer CTs outside of that range," he said.

Director of Stakeholder Affairs Dave Anders said the Energy Market Uplift Senior Task Force, which overwhelmingly approved the proposed change in February, may consider "friendly amendments" at its April 17 meeting.

The MRC is expected to vote on the issue at its next meeting, April 23.

Geomagnetic Disturbance Causes Spikes, No Operational Problems

An unexpected geomagnetic disturbance (GMD) March 17 caused brief spikes on PJM's grid but no operational problems, RTO officials told the Operating Committee last week.

Some of PJM's approximately 50 geomagnetically induced current (GIC) meters recorded spikes of more than 20 amps, but the jumps were short-lived and did not cause PJM to direct conservative operations.

The National Oceanic and Atmospheric Administration, which normally provides one to three days' advance notice of such events, didn't warn PJM and other grid operators until the morning of the 17th, said Chris Pilong, manager of dispatch.

NOAA predicted "a glancing blow" centered at 50 degrees latitude — near Winnipeg, Manitoba. As it turned out, the solar storm was a bit more intense than expected and centered a bit farther south, Pilong said.

Still, the incident did not pass PJM's threshold for initiating conservative operations — a rise of 10 amps for more than 10 minutes. Pilong said the longest spikes lasted no more than four minutes.

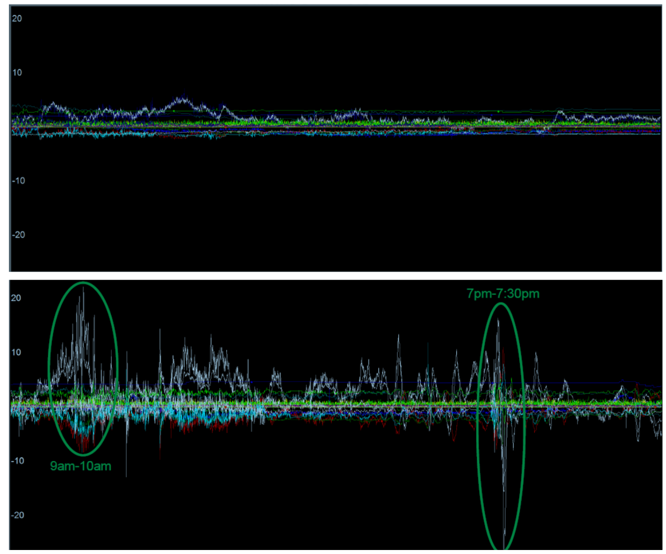
"This is the highest measurement I can recall seeing in some time and we saw no impact on the system," he said.

NOAA initially predicted a G-3 (strong) event for three hours beginning at 8 a.m. ET. It upgraded the storm to a G-4 (severe) with a lower latitude of 45 degrees — near Montreal — and a six-hour duration.

The GIC meters recorded their biggest spikes between 9 and 10 a.m. and 7 and 7:30 p.m. (See graphic.)

The incident came less than two weeks before the North American Electric Reliability Corp.'s Geomagnetic Disturbance Operations Standard (EOP-010-1) took effect on April 1. The standard requires reliability coordinators to review the GMD operating procedures or processes of transmission operators (TOPs) within their areas to mitigate the effect of GMDs on the grid.

The Federal Energy Regulatory Commission approved the standard, the first phase of rules to protect the grid from GMDs, last June. (See FERC OKs GMD, Training Standards; Proposes Modeling Rule Change.)



Geomagnetic disturbance readings, in amps, on a normal day (top) and March 17 (below). (Source: PJM)

PJM Ponders Expansion of Winter Generator Testing

PJM is considering stakeholder suggestions that it expand the winter generator testing it initiated last winter.

That testing was voluntary and limited to units that hadn't run for the prior two months. It was credited with reducing generator outages to a peak of 10% in January 2015, compared with a high of 22% a year earlier.

Mike Bryson, executive director of system operations, told the OC that some stakeholders have suggested the testing be made mandatory.

In early November, PJM identified about 55,000 MW of generation that was eligible for testing because it had not operated for the prior two months. The number dropped to about 44,000 MW after some of the units were dispatched during an early November cold spell.

Owners of about half of the remaining units submitted them to PJM for testing, but the RTO ended up testing only about 9,000 MW because of a 1,000-MW cap on tests per day and because warm weather prevented testing on some days.

The temperature threshold "knocked most of the days out" for testing in the Dominion zone, Bryson said.

PJM officials plan to discuss the issue internally before bringing a proposal to stakeholders, Bryson said.

New Info on Planned Outages to be Shared

PJM plans to start posting additional information on scheduled transmission outages in its OASIS system in response to requests for such details.

Beginning with the third-quarter eDart release in September, the following information will be available: the queue number; the time that the outage equipment can be returned to service at PJM's request; and a "questionable approval" indicator, which will inform market participants that the outage may not be approved by PJM.

PJM Concerned Fast Response Regulation Crowding Out Traditional Resources

PJM operators are concerned that fast response regulation resources are taking too large a share of the RTO's overall regulation response.

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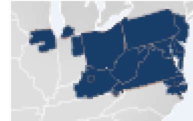

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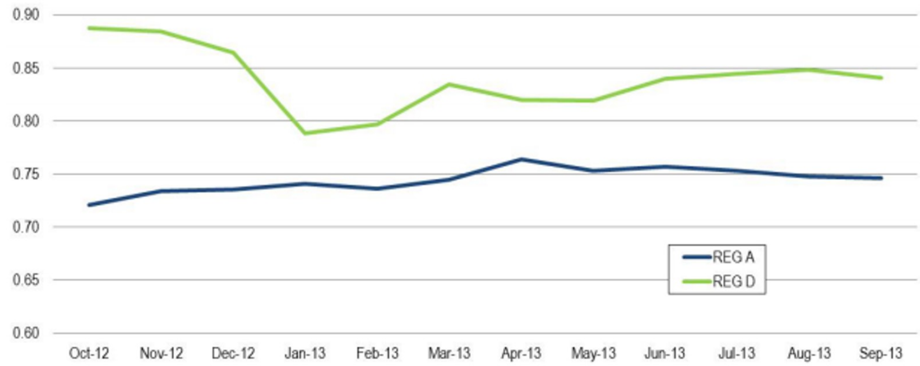
PJM's Danielle Martini presented a proposed problem statement on the issue to the OC last week.

Fast-responding RegD are providing more than 42% of total response on average, with shares as high as 70% during some events, Martini said. That leaves less room for slower-responding RegA resources.

"Too much RegD looks like it hurts performance because it affects how much RegA we procure," Mike Bryson, executive director of system operations, explained after the meeting.

PJM is considering whether to use a different regulation signal for energy-limited resources such as participating in the regulation market.

"This scenario is seen most frequently when the RTO experiences high or low [area control error] during periods of rapid load changes during the morning and evening periods," the problem statement said. "During these times, the regulation signal is utilized to maintain ACE control if the load ramp briefly and instantaneously 'slows down' or 'speeds up.' During these times, larger sized units are coming on line and offline (hydro, CTs, etc.) to keep up with the load, and regulation is critical in correcting for the instantaneous changes in load and generation.



Average performance scores by regulation type (Source: PJM)

"When the regulation signal 'times out' for RegD resources and there is a large amount (>42%) of RegD providing the regulation service, the dispatcher is left with limited resources with which to maintain control of the system. This may lead to increased periods of ACE/BAAL excursions and increased reliance on synchronized reserves to supplement the temporarily depleted regulation reserves."

— Rich Heidorn Jr.

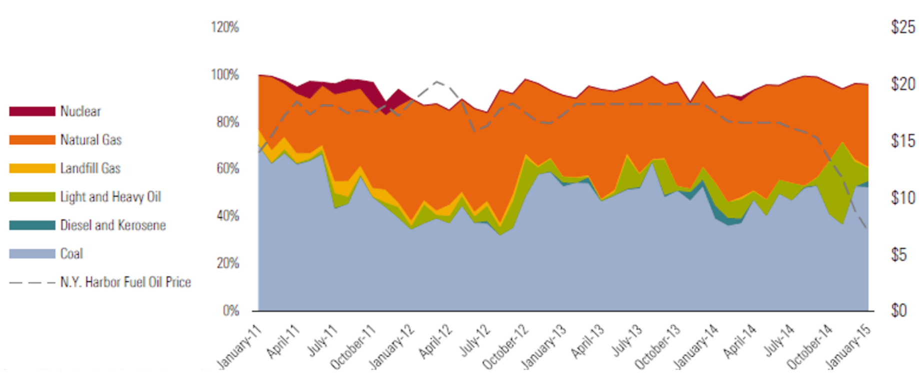
Morningstar: PJM to Hit Record Spark Spreads in 2015-16

The next year will be a good one for natural gas-fired generators in PJM, according to Morningstar Commodities Research.

A new report by Morningstar analyst Jordan Grimes predicts on-peak prices at PJM's West Hub will result in "historically high" spark spreads in delivery year 2015-16. Spark spread, a measure of gas plants' gross profit margin, is the difference between the price received by a generator for power and the cost of the gas needed to produce it.

Grimes says physical reserve margins will tighten due to the retirement of more than 10,000 MW of older coal, gas and oil capacity before June 1.

"New combined-cycle capacity will replace some of this lost capacity, but much of the physical capacity will be replaced with demand response, renewables and expected imports from neighboring ISOs," he wrote. "When DR replaces physical capacity, it will steepen the supply curve at the same time physical reserve margins drop this summer."



Fossil fuels on margin in PJM (percentage of on-peak hours).
(Source: Morigstar, Monitoring Analytics, NYMEX)

For a gas plant with a 7,000 Btu/kWh heat rate purchasing gas at Tetco-M3 and selling power at PJM West, that could lead to spark spreads averaging $25/MWh in calendar year 2015 and $22/MWh in 2016, Grimes predicts.

But he says spreads will decline to $18 in 2017 and $16 in 2018 as more new combined-cycle plants are built in PJM and pipeline expansions allows Marcellus gas producers to obtain higher prices from more distant customers.

"There are a few scenarios … that would help keep spark spreads elevated in 2017 and 2018, but the most likely scenario is lower spark spread clears, given the new, more efficient supply stack and higher Tetco-M3 gas prices," Grimes said.

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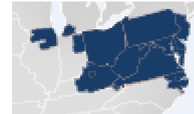


Planners Set April 28 for Artificial Island Recommendation

By Suzanne Herel

VALLEY FORGE, Pa. — PJM planners said last week they will announce their revised recommendation to address stability problems at the Artificial Island nuclear complex at a special Transmission Expansion Advisory Committee meeting April 28.

Planners recommended Public Service Electric & Gas for the project last June, but the Board of Managers reopened the bidding to finalists Transource Energy, Dominion Resources and LS Power after criticism from environmentalists, New Jersey officials and spurned bidders.

All of the potential solutions involve new transmission lines connecting Artificial Island to Delaware. LS Power and Transource have proposed a southern crossing of the Delaware River. Dominion and PSE&G offered a northern route with an overhead crossing.

Planners had hoped to announce their revised selection in January but delayed their decision to allow consultants to investigate concerns that Dominion's proposed use of thyristor controlled series compensation (TCSC) could threaten reliability at the island, home to the Salem-Hope Creek nuclear complex. (See *Further Study Delays PJM's Artificial Island Decision*.)

PSEG Nuclear, which operates the nuclear plants, contends Dominion's proposal would use unproven technology that could result in damage to turbine generator shafts.

Planners told TEAC members last week Siemens Power Technology International had completed its sub-synchronous resonance analysis of Dominion's proposal and found that the TCSC could result in "negative damping" for several resonant frequencies.

However, Exponent, an engineering and science consulting firm that reviewed the Siemens study at PJM's request, said it was "inconclusive" because of limits in the data available.

Exponent expressed its own concerns with the Dominion proposal. It said Dominion is proposing a 90% post-contingency TCSC compensation — well above the 70 to 80% compensation used by others in the industry.

Responding to questions from stakeholders who suggested more study might be needed to verify the feasibility of the Dominion proposal, Steve Herling, vice president of planning, said Siemens had identified the "potential for an issue."

"It's not a fatal flaw," he said.

"[I]t's an issue going forward," said Thomas Leeming, director of transmission operations and planning for Exelon's Commonwealth Edison. Not "having wrestled this to the ground could be an issue."

"We understand what needs to be done if we go that way," Herling responded. "We recognize that if we go with this solution there's more work to be done. We've already talked to a number of manufacturers about all these issues."

Planners said their current schedule would result in a recommendation to the Board of Managers' Reliability Committee on May 19.

Tx Developers Challenge PJM Choice on Pratts Project

By Suzanne Herel

VALLEY FORGE, PA — Two competing transmission developers are challenging PJM's selection of Dominion Resources and FirstEnergy to resolve reliability problems near Pratts, Va. (See *Dominion, FirstEnergy Recommended for Pratts Solution*.)

ITC Holdings and Northeast Transmission Development sent PJM letters questioning the decision and arguing in favor of their own proposals.

In its letter, dated March 24, Northeast Transmission, a unit of LS Power, said the two proposals it submitted are more efficient and cost-effective than PJM's choice.

"NTD does not believe that PJM appropriately considered the cost cap provided by NTD relative to cost 'estimates' for alternative proposals," it said.

It also asked PJM to consider two project combinations, either of which it said would save an estimated $28.8 million to $58.8 million and provide cost containment. One of the combinations also would offer reduced risk through use of an existing right-of-way, the company said.

ITC's letter, dated April 7, called on PJM to reconsider its proposal, which it called "nearly identical" to the one from Dominion and FirstEnergy.

"To resolve this issue equitably, and ensure the evaluation of proposals on an even playing field, we request the PJM perform additional analysis to compare the ITC proposal with the Dominion-FirstEnergy proposal before making a recommendation to the PJM board."

Four developers suggested 16 proposed solutions, but PJM concluded only six of the proposals solved the violations. PJM said the Dominion-FirstEnergy proposal was selected in part because the companies own the substations involved and most of the rights-of-way required. In addition to project risk, PJM said it considered performance and cost-effectiveness in its selection.

Paul McGlynn, PJM general manager of system planning, told the Transmission Expansion Advisory Committee that planners will review the competitors' letters and consider changes to their recommendation "if they are in fact warranted."

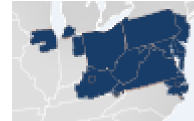
McGlynn said planners will return the issue to the TEAC for another discussion before making a final recommendation to the PJM board.

Sharon K. Segner, a vice president for LS Power, questioned why the Dominion-FirstEnergy proposal should receive a preference for owning substations and rights-of-way when any developer selected would be able to invoke eminent domain to acquire needed land. She added later that Virginia has established precedent that new entrants can obtain public utility status.

"You're certainly entitled to your opinion," McGlynn responded.

Segner also said PJM should consider identifying the top three or four most important criteria it will consider when it issues future competitive solicitations, as she said is the practice in CAISO's Order 1000 process. McGlynn said performance, cost effectiveness and risk will always be top priorities, although their relative weighting may vary from project to project.

PJM NEWS



PJM Planning Committee Briefs

Planners Considering Additional Changes to Light-Load Studies

Transmission planners are considering additional changes to their light-load studies based on a reevaluation of three years of data that showed coal- and natural gas-fired generation are operating at higher capacity factors than previously assumed. Planners already had concluded that maximum wind capacity factors should be increased in the studies.

The analysis showed that capacity factors for coal generators during light-load periods — 1 to 5 a.m. from Nov. 1 through April 30 — have been trending up, in large part because retiring units are leaving more electricity to be generated by those remaining.

Planners are considering increasing the maximum ramping of coal plants 500 MW and larger above the current 60% and boosting the assumptions for coal plants below 500 MW above the current 45% maximum. PJM also is weighing an increase in assumptions for natural gas plants; planners currently assume they are not dispatched at all during light-load periods.

The analysis found large plants operated above the 60% capacity factor in about two-thirds of light-load hours RTO-wide during delivery year 2013-14, with the APS and AEP zones above that level about 80% of the time. Smaller coal units operated above their assumed capacity factor in about half of the hours RTO-wide. In APS, small coal ramped above the assumption in all light-load hours for the year, Mark Sims, manager of transmission planning, told the Planning Committee last week.

"A significant amount of coal has retired. What's left is running more often because it's more efficient and competitive," Sims said.

Capacity factors also have been increasing during light-load hours for natural gas combined-cycle units as the fuel has become cheaper. RTO-wide, they operated in about one-quarter of light-load hours, with units in the AEP zone running in 86% of hours. When they are operating, they are generally doing so at capacity factors of 80% or higher.

No changes in assumptions are proposed for oil (assumed at 0%) and nuclear units (assumed at 100%).

PJM last month announced its intention to increase the maximum wind capacity factor from 80% to 100%, consistent with the modeling in MISO. (See *Changes Proposed for Light Load, Wind Modeling*.)

Sims said staff will conduct sensitivity analyses after finalizing their recommended changes and report back to the PC.

PJM Looks to Tweak Peak Load Forecast

PJM plans to recommend changes to improve its peak load forecasts by the end of June, officials told the PC. The revised model is an effort to better reflect customer usage, energy efficiency, weather and the impacts of "behind the meter" solar generation. (See *PJM Seeking Improved Load Forecasts*.)

PJM's John Reynolds said efficiency in heating is continuing to climb, though not as dramatically in recent years. Meanwhile, cooling efficiency has leveled off and overall energy usage for cooling is expected to begin increasing by 2020.

PJM also is investigating the impact of distributed solar energy on demand. More than 1,700 MW of photovoltaic solar generation not registered as capacity resources is now receiving solar renewable energy credits in the PJM region, up from zero in 2005. Reynolds said most of the generation is in New Jersey, which has generous solar subsidies.

Planners expect to identify improvements to the model by the end of the second quarter, with revised manual language brought to stakeholders for endorsement by the end of the third quarter. Any changes would be implemented in the 2016 load forecast.

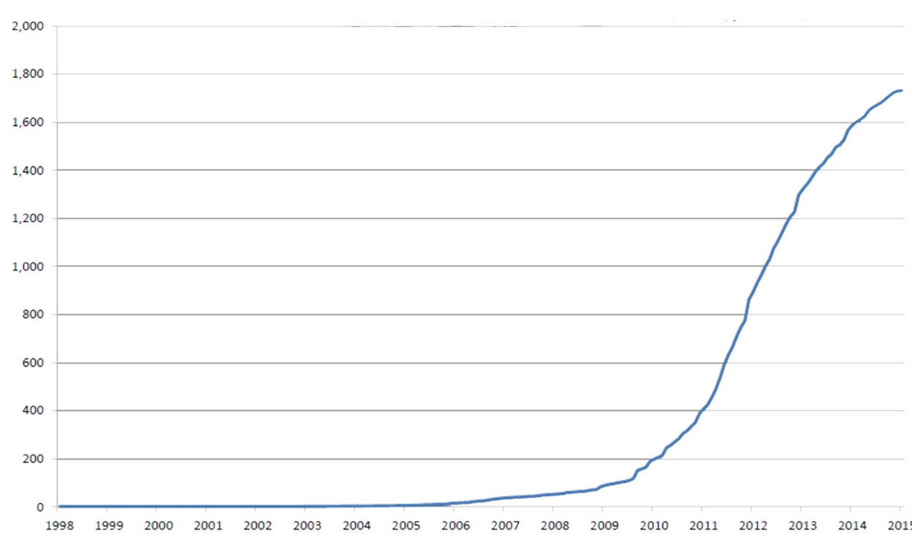
Long-Term Firm Transmission Study Endorsed

Members unanimously endorsed creating a Planning Committee sub-group to consider changes in how it studies long-term firm transmission service requests. The effort, initiated with a problem statement approved in March, is intended to ensure that individual requesters share in the cost of transmission upgrades required to serve them. (See *Change Would Shift Baseline Upgrades to Network Customers*.)

"PJM's process, tools and thresholds have been established based around a local generation or transmission injection projects' impacts and not around remote origination of energy," according to the issue charge approved by members.

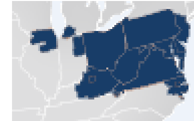
The group is expected to complete its deliberations by the end of the third quarter.

Continued on page 10



Photovoltaic renewable generator registers in GATs within PJM but not grid-connected (nameplate capacity in megawatts). (Source: PJM)

PJM News



UTC Trader: Firm was Ruined by 'Unfair' FERC Prosecution

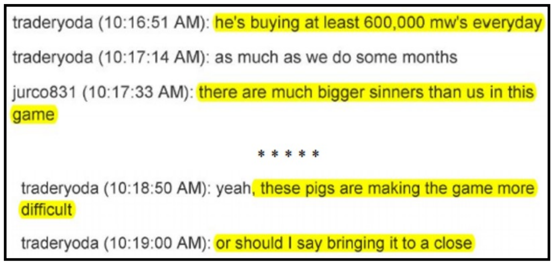
By Ted Caddell

A Florida power trader under investigation for market manipulation over up-to-congestion trades says the transactions were lawful and that an "unfair" investigation by the Federal Energy Regulatory Commission has ruined his business. He asked for a review of his case by the full commission (IN15-5).

According to FERC's Office of Enforcement, Stephen Tsingas and his firm, City Power Marketing, made $1.2 million in July 2010 through "fraudulent" and risk-free round-trip UTC trades placed solely to collect line-loss rebates. The allegation is almost identical to what FERC made in the pending case against Rich and Kevin Gates and their Powhatan Energy Fund.

Tsingas' April 7 filing is in response to the demand by FERC Enforcement that it show why he and City Power shouldn't return the profits and pay $15 million in fines.

Tsingas' defense is similar to that of the Gates brothers: He argues that when the trades were undertaken there was no direct prohibition of them. When PJM's Independent Market Monitor raised objections to the transactions, Tsingas says, he and City Power discontinued them.



traderyoda (10:16:51 AM): he's buying at least 600,000 mw's everyday

traderyoda (10:17:14 AM): as much as we do some months

jurco831 (10:17:33 AM): there are much bigger sinners than us in this game

* * * * *

traderyoda (10:18:50 AM): yeah, these pigs are making the game more difficult

traderyoda (10:19:00 AM): or should I say bringing it to a close

FERC investigators cited instant messages such as these in July 2010 in their case against City Power. (Source: FERC)

Tsingas also denied an allegation that he concealed documents during the investigation. Tsingas and his attorneys say a series of instant messages that FERC purports to show collusion are taken out of context.

Tsingas' legal team — which includes Todd Mullins, a former branch chief in the Office of Enforcement's Division of Investigations — says the investigation effectively put City Power out of business.

"Staff's investigation of this handful of trades has destroyed CPM," they wrote. "Once a company with eight employees and gross revenues exceeding $8 million annually, CPM now only has one employee — Mr. Tsingas.

"The stress of an investigation that has lasted almost five years, along with the enormous expenses incurred as a result, have ruined the company even before any tribunal — judicial or administrative — has had the opportunity to determine the merits of staff's accusations."

The crux of the defense is that to be prosecuted for manipulation, there must be a showing of "fraud or deceit." Tsingas claims that when the trades were undertaken there had not yet been a determination that the trades were anything but legal transactions that may have taken advantage of a market weakness.

"There was no false information injected into the marketplace," Tsingas' lawyers wrote. "There was no artificial price formation. There was no violation of the [commission's] Anti-Manipulation Rule. CPM traders were simply responding to the predictable incentives created by the market.

"The commission cannot and should not turn into a violation every case in which [a] participant trades in a manner consistent with the rules as then written and involving no falsity just because the trader may have had a motive for the trade that was not what the commission … had in mind," they argued.

PJM Planning Committee Briefs

Continued from page 9

Committee Endorses Reserve Requirement Study

The PC approved revised assumptions for the 2015 PJM reserve requirement study that are expected to have a minor impact.

The study will determine the installed reserve margin, forecast pool requirement and demand resource factor for future delivery years and will look at the period from June 1, 2015, through May 31, 2026.

The two changes of note regard the computation of demand response and PJM's proposed Capacity Performance product.

The study will use PJM's new method of modeling demand response, which takes the average of the final amount of committed DR for the most recent three years. Previously, forecasters used the amount that cleared the last Base Residual Auction. (See *Members Endorse Change to Demand Response Modeling*.)

And, because the RTO's Capacity Performance plan is in limbo as it awaits a ruling from the Federal Energy Regulatory Commission, the study will report using two sets of parameters — one with the CP product and one under the status quo. The forecast pool requirement values that ultimately will be applied will depend on whether FERC approves PJM's plan. (See related story, *PJM Responds to FERC Queries on Capacity Performance, Requests Approval*, p. 1.)

Order 1000 Problem Statement Approved

The PC approved a problem statement formalizing its work on process improvements as a result of Order 1000 "lessons learned."

Although PJM already has begun incorporating the lessons — for example, introducing an improved method for receiving document submissions from transmission developers — officials said they decided a problem statement was needed because the issue would be a "standing agenda item" for the committee in the future.

PJM's first project under the order, soliciting a fix for stability issues at New Jersey's Artificial Island nuclear complex, has been beset by numerous delays and controversy. Planners expect to recommend a proposal to the Board of Managers next month — more than two years after the competitive window opened. (See related story, *Planners Set April 28 for Artificial Island Recommendation*, p. 8.)

— Suzanne Herel

NYISO News

Appeals Court Ratifies New York Capacity Zone

By William Opalka

A federal appeals court has rejected challenges to the Lower Hudson Valley Capacity Zone in New York (14-1786).

Utility companies and the New York Public Service Commission had appealed an August 2013 order by the Federal Energy Regulatory Commission creating the zone, saying it would lead to a windfall for power generators. (See New Yorkers Upset over NYISO Capacity Zone.)

A three-judge panel of the U.S. Second Circuit Court of Appeals ruled in favor of FERC on April 2 in a 61-page opinion.

"We conclude that FERC articulated sound economic principles supporting the creation of the Lower Hudson Valley Zone and satisfactorily explained how those principles justified its conclusion," the court said.

The options for the losing parties are to ask for an *en banc* rehearing before the entire court or to directly petition the U.S. Supreme Court.

"We are disappointed, as the capacity zone has unfairly and artificially raised energy prices for homes and businesses in our service territory. We are reviewing the court's decision, however our legal options are very limited as there are no reasonable or promising actions available to us," said Central Hudson Gas & Electric spokesman John Maserjian.

Central Hudson says monthly bills have increased by 6% for residential customers and 10% for large industrials.

NYISO, in response to previous FERC orders, created the zone in the counties north of New York City in August 2013. The lawsuit challenging was filed after additional charges in the zone went into effect May 1, 2014.

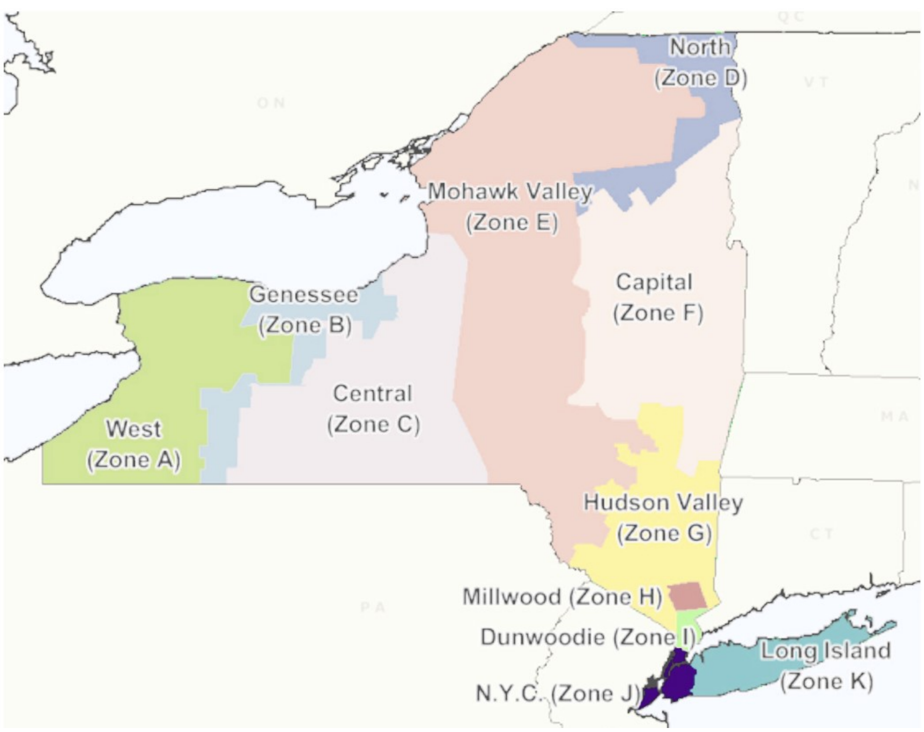
NYISO and FERC maintained that generation resources were needed because price signals were insufficient to encourage power plant developers to site facilities there and that transmission constraints threatened reliability.

"We are not persuaded that there is anything unreasonable in FERC's conclusion that higher prices were necessary to ensure reliability by generating accurate price signals in the long run," the court wrote.

FERC said the congestion issue has been discussed since 2006 without a solution. Consumers have been shielded from higher prices since that time, it noted.

The companies and the PSC had argued that proposed transmission projects would relieve the constraints. (See Tx Plan to Open NY Choke Points Without New ROWs.) Another project would create a corridor from the Canadian border to New York City, making renewable energy generation from upstate more readily available.

The court sided with FERC's contention that the projects have not yet been certified and that FERC "rationally explained its decision to act according to existing market conditions rather than speculative future conditions."



New York capacity zones. (Source: FERC)

FERC Requests More Info on NYISO VSS Change

The Federal Energy Regulatory Commission says a filing made by NYISO to calculate payments for voltage support services (VSS) is deficient (ER15-1042).

The commission Friday requested more information before it can consider amendments to NYISO's Market Administration and Control Area Services Tariff.

NYISO proposed paying VSS providers $2,592/MVAr for both leading and lagging capability, with annual increases based on the consumer price index (CPI). MVAr is the unit of measurement for reactive power capability. (See NYISO Rejects Protests on Voltage Compensation.)

FERC asked NYISO for more explanation of the methodology and assumptions used to determine the proposed rate. It also ordered the ISO to provide documentation demonstrating that the proposed amendments maintain the approximate total dollar value of the current VSS program in the near term.

The Independent Power Producers of New York and Dynegy Marketing and Trade filed separate protests asking FERC to order the ISO to increase the compensation rate to reflect inflation since the existing rate was set in 2002.

— William Opalka

NYISO News

Opponents Seek More Time in Ginna Rate Review

By William Opalka

Opponents of a financial lifeline for the R.E. Ginna nuclear plant had their bid for more time to allow them to prepare their challenges turned down by administrative law judges overseeing the case.

Environmentalists and industrial consumers contended the current schedule will deny ratepayers due process in a case that could cost them $175 million.

The New York Public Service Commission has ordered initial "issue statements" by April 15 in a review of the ratepayer impact of a reliability support services agreement between Rochester Gas & Electric and Exelon's Constellation Energy Nuclear Group, the plant's owner. (See *Action on Ginna RSSA Delayed 4 Months*.)

The PSC ordered the utility to make a deal to keep the plant operating after regulators and NYISO determined the plant was needed to maintain system reliability. A flurry of filings have been made over the past two weeks as supporters and opponents of the deal vie for position (14-E-0270).

Those filings "have not established a basis for us to conclude that an extension of the deadline for submitting issue statements is necessary," the judges wrote. They also cited the coming summer peak demand, the reliability needs provided by the plant and Ginna's right to cancel the agreement on July 1 as reasons to keep to the established schedule.

The judges said they were being asked to make rulings on the merits of the agreement in what is meant to be a procedural phase of the case. "We must establish a schedule that preserves the full range of possible outcomes for commission review and decision, without, in practical effect, deciding substantive issues," they added.

Opponents asked the PSC for more time to make their case against the deal, while the utility, plant owner and PSC staff want to maintain a schedule that would close the case by July 29. If approved, the agreement would be retroactive to April 1 and last through September 2018.

The Alliance for a Green Economy and Citizens Environmental Coalition joined the opposition in an April 1 filing in which they also challenged the hearing schedule. The groups said the April 1 effective date of the contract was arbitrary.

"It is unreasonable to saddle Rochester-area customers with retroactive costs and interest payments that will start accruing before there has been time for [the] public to comment on the proposal or for the Public Service Commission to review the case," they said.

They added that in a "major rate proceeding," the PSC staff and interested parties have three to four months to conduct discovery. "The relief sought in this case is distinguishable from that which is sought in a typical major rate filing," the judges wrote, citing the PSC order and the limited issue it posed.

The Utility Intervention Unit of the state's Consumer Protection Bureau also challenged the effective date, "which was arrived at without the benefit of the parties' input, [and] should not be used as a justification for limiting the parties' due process opportunities to participate effectively in this proceeding."

About 60 commercial, industrial and institutional customers said they support a one-month delay as a "reasonable" time frame to resolve issues before hearings with administrative law judges.

The PSC staff disagreed, saying that the schedule — which allowed 45 days for public comments — meets state law and balances the need to provide adequate time for the public to comment.

MISO News

MISO TOs Seek Base ROE of 11.39%

By Chris O'Malley

MISO's transmission owners have told the Federal Energy Regulatory Commission it should order only a modest reduction in their base return on equity to 11.39%, not the 9.15% sought by industrial customers.

On April 6, the TOs filed an analysis contending 11.39% represented "a logical and supportable estimate of the cost of equity." Omitting the FERC-approved ROEs for ITC Holdings — the only publicly traded transmission-only company in the U.S. — would result in an "absolute minimum" base ROE of 10.8%, the analysis said.

MISO industrial customers initiated the ROE dispute last fall, contending that transmission operators' current base return on equity — 12.38%, except for American Transmission Co. at 12.2% — is too high (EL14-12).

The industrials contend the base ROE for TOs should not exceed 9.15%, citing changes in financial markets and other factors. They say the lower base ROE would cut transmission rates by about $327 million annually.

The dispute last year went into settlement discussions, but talks broke down in December.

After it became clear the case would not settle, the MISO Public Consumer Group sector joined in the fight, in what is its first-ever litigation in a FERC rate case.

In February the sector — which includes both non-profit groups and government agencies that represent consumers in utility cases before state regulators — asked MISO for $200,000 to help cover its legal costs in the dispute. (See *MISO Advisory Committee Briefs*.)

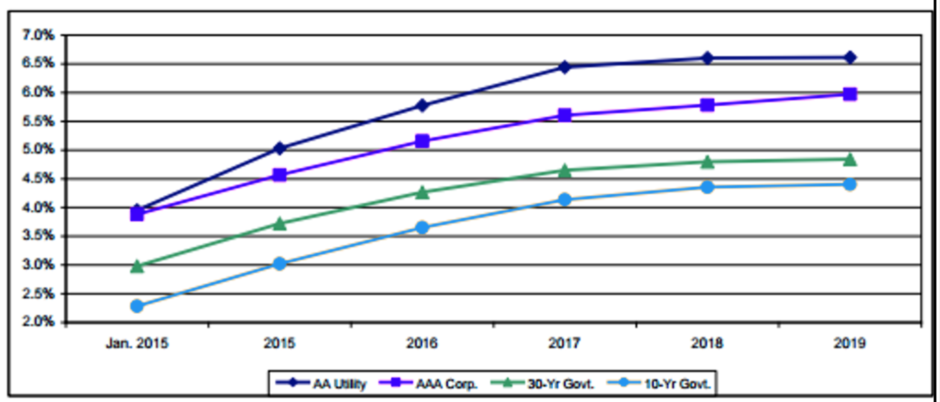
MISO spokesman Andy Schonert said last week that the RTO "continues to consider stakeholder feedback [on the request] and will be finalizing [its] decision quickly."

On April 3, the consumer advocates asked FERC for approval to amend the group's intervention by adding the Arkansas Attorney General's Consumer Utility Rate Advocacy Division; the Kentucky Attorney General's Office of Rate Intervention; the Louisiana-based Alliance for Affordable Energy; the Montana Consumer Counsel; and the Illinois Attorney General.

"As the outcome of the joint consumer advocates funding request has not yet been determined, it is even more important to broaden consumer advocate engagement in this proceeding in order to build up resources to support the Consumer Advocates' participation in this case," wrote Jennifer Easler, an attorney in the Iowa Office of Consumer Advocate.

The dispute follows FERC's ruling last June that introduced a new, two-step method for calculating transmission owners' ROEs. Ruling in a case involving New England TOs, FERC tentatively set the "zone of reasonableness" at 7.03 to 11.74%.

Interest Rate Trends



(Sources:
Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 21, 2014)
HIS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014)
Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
Blue Chip Financial Forecasts, Vol. 33, No. 12 (Dec. 1, 2014)
via MISO Transmission Owners' ROE analysis (EL14-12-002))

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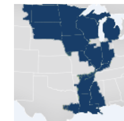

MISO-PJM Cross-Border Projects Still Languishing, NIPSCO Says

Continued from page 1

NIPSCO's filing was one of almost a dozen responses FERC received from MISO and PJM stakeholders in response for its request for comments on six rule changes proposed by NIPSCO. (See related story, *FERC Floats Possible Orders on PJM-MISO Seam*, p. 15.)

FERC posed the questions as preparation for a yet-to-be-scheduled technical conference on the issues raised in NIPSCO's complaint (EL13-88).

Three-Step Process

NIPSCO wants FERC to order the MISO-PJM cross-border transmission planning process to run concurrently with, rather than after, the RTOs' regional transmission planning cycles.

Without such a change, NIPSCO said, it would take more than three years for a beneficial market efficiency project to navigate its way through the three independent processes currently in place.

As an example, NIPSCO pointed to its proposed Reynolds-Wilton Center project, which had been part of the market efficiency study process in MISO's Transmission Expansion Plan (MTEP13).

Proposed in May 2012, the project was found by MISO to have a strong benefit-to-cost ratio and would have had significant benefits for PJM, NIPSCO contends.

The project was put on hold until it could be studied in the Interregional Planning Stakeholder Advisory Committee process. It didn't pass; MISO re-evaluated the project a year later, but it didn't pass MISO market efficiency metrics.

Had it passed IPSAC, however, it would

Continued on page 15

MISO Staff Hold Firm in Support of Entergy Out-of-Cycle Request

By Chris O'Malley

Responding to a new round of objections by the transmission developer and independent power producer sectors, MISO management has reiterated its recommendation that $200 million in proposed out-of-cycle projects by Entergy be approved by the RTO.

"We continue to recommend approval by the board at the April meeting" of the six out-of-cycle projects, Jeffrey Webb, senior director of expansion planning, told the System Planning Committee of the Board of Directors on April 7.

The largest and most controversial of the out-of-cycle projects is $187 million in transmission improvements Entergy said are necessary to support a wave of new industrial development in the Lake Charles, La., region.

The committee took up the issue in March but stopped short of endorsing the Entergy projects despite a request to do so by Entergy Louisiana CEO Phillip May. (See *MISO Board Questions Execs on Entergy Out-of-Cycle Requests.*)

The full board has been invited to take part when the matter is discussed again by the committee on April 21. That is two days before the April 23 board meeting, when a final vote is expected.

MISO staff provided point-by-point rebuttals to written objections that dissenting sectors recently filed with the Planning Advisory Committee. The objections repeated complaints made earlier, challenging the certainty of Entergy's load projections and questioning whether the projects were larger than needed to meet base reliability needs. They also alleged MISO failed to follow its Business Practices Manual, limiting opportunity for thorough stakeholder review.

In regard to the assertion that Entergy hasn't provided sufficient evidence of underlying load projections, MISO staff insisted that nothing in the Tariff requires a load-serving entity to provide "verification and additional supporting documentation" for load projections.

MISO said Entergy's growth projections are consistent with "widely publicized" projections of significant new industrial developments.

MISO's Legal Obligations

System Planning Committee members inquired about MISO's legal obligations in vetting out-of-cycle project requests. General Counsel Steve Kozey said MISO generally must make a good faith effort, but it is neither MISO's nor the board's role to litigate to a third party's satisfaction.

Committee member Eugene Zeltmann pointed to comments filed by the Transmission Developer sector that suggested some transmission equipment included in the current out-of-cycle request was also part of a 2014 request, suggesting that it may be double-counted.

MISO staff replied that MISO staff did not double count that equipment and that it was distinct from earlier out-of-cycle projects.

Committee Chairman Michael Evans asked Webb to respond to concerns by some stakeholders that MISO did not provide adequate time for stakeholders to comment on the out-of-cycle requests.

Webb said an out-of-cycle request by its nature is necessarily "a compressed" time period but that staff abided by procedures.

Stakeholders Split

A stakeholder opposing the Entergy's out-of-cycle requests was equally resolute.

"We continue to disagree with MISO staff," said George Dawe of Duke-American Transmission Co., who represents the Competitive Transmission Developer sector.

He added that the process followed by the RTO "has called into question MISO's credibility."

But Lin Franks, senior strategist at Indianapolis Power & Light, countered that what Entergy has proposed is indeed a reliability project and that she doubted that board members wanted to be accused of causing delays leading to reliability problems.

"This is a reliability issue and not an economic one," she said.

MISO-PJM Cross-Border Projects Still Languishing, NIPSCO Says

Continued from page 14

have taken 42 months, NIPSCO estimates.

As it stands, a project would first have to pass through one regional process, with its specific metrics and an independent model built for that study year. Then it would have to pass an interregional process with specific metrics. Lastly, it would have to pass the final regional process again with its specific metrics and model, NIPSCO said.

"Over 10 years of history have verified that no developer has had the necessary foresight or fortitude to successfully run the gauntlet of the MISO-PJM interregional process. NIPSCO, therefore, does not believe that it is possible for a project to navigate all three existing processes."

NIPSCO is not alone in that view. Southern Indiana Gas & Electric also faulted the three-step process in its response to FERC's questions.

Other Views

But other stakeholders, including ITC Transmission, said they don't believe that forcing the cross-border and regional transmission planning processes to run concurrently is the most effective approach. ITC recommends that FERC require MISO and PJM to eliminate the three-step approval process altogether.

Instead, ITC said that projects approved in the coordinated system plan under provisions of the MISO-PJM Joint Operating Agreement should automatically be recommended for approval by both RTOs for cost allocation in their respective regional transmission plans.

"MISO and PJM should also establish a new project category for 'interregional projects' in their respective regional planning processes," ITC said.

Among other stakeholders weighing in is AEP, which maintains that modifying the JOA to conduct concurrent joint and regional studies with identical criteria "is simply untenable."

AEP said each RTO has planning criteria to address its regional needs, plus has to coordinate with other transmission systems whose regional planning criteria may differ. AEP also said FERC Order 1000 specifically recognizes that regional differences are valid.

As for cross-border market efficiency projects, AEP suggests that each RTO use its regional study process to quantify its regional market efficiency needs and congested flowgates. They also should invite stakeholders to submit both regional and interregional proposals.

"If the sum of each RTO's portion meets or exceeds the total cost of the interregional proposal, then the proposed interregional project would be included in the list of finalists from which the most efficient and cost-effective projects would be selected," AEP said.

Cost apportionment of approved cross-border projects would be in proportion to the market efficiency benefits that each RTO derives, AEP said.

RTOs: Process is Improving

MISO and PJM rejected assertions that their regional transmission planning cycles are impeding cross-border projects.

In joint comments to FERC, the RTOs say they already have a "highly aligned" interregional planning cycle.

In a joint 2014 study, both RTOs evaluated cross-border transmission issues and identified opportunities for more than 80 projects "using a single model with a single set of mutually agreed upon assumptions."

"Although no project passed the interregional or regional criteria, any interregional projects would have had timely approval in both the regional and interregional processes," the RTOs said. "Accordingly, the respective planning cycle timing and synchronization was not an issue; rather, the fact that projects did not pass the cost/benefit analysis exclusively relates to the criteria themselves rather than any mismatch in the timing or lack of coordination between the interregional planning analysis and the respective RTEP and MTEP processes."

'Quick Hit' Projects

Since NIPSCO's complaint, the RTOs noted, they have proposed to build at least 26 "quick hit" transmission projects that could be done quickly and cheaply on lower voltage flowgates to address constraints on both sides of their seam. (See *MISO, PJM Ponder List of 'Quick Hit' Upgrades*).

PJM officials told the Transmission Expansion Advisory Committee last week that the projects could eliminate $280 million of the $400 million in annual congestion at the top 38 historical market-to-market constraints.

PJM's Chuck Liebold said the quick-hit effort resulted after planners asked themselves, "Are we missing something that would be easy to do?"

"We're trying to do the right thing," he said. "We've had studies that haven't produced any projects."

FERC Considering NIPSCO Proposals on PJM-MISO Seam

On Feb. 12, the Federal Energy Regulatory Commission asked for comments on the pros and cons of six potential rule changes intended to push PJM and MISO to create cross-border transmission projects (EL13-88). The changes were proposed by Northern Indiana Public Service Co. (NIPSCO) in December 2013.

The commission asked commenters to opine on the costs and technical feasibility of implementing requirements that MISO and PJM:

- Run their cross-border transmission planning process concurrently with the RTOs' regional transmission planning cycles, rather than after them.
- Develop a single model that uses the same assumptions in the cross-border transmission planning process. Until the joint model is developed, the RTOs would be required to ensure consistency between their planning analyses and apply their reliability criteria and modeling assumptions consistently.
- Use a common set of criteria in evaluating cross-border market efficiency projects.
- Consider all known benefits, including avoidance of future market-to-market (M2M) payments made to reallocate short-term transmission capacity in real-time operations, when evaluating cross-border market efficiency projects.
- Establish a process for joint planning and cost allocation of lower-voltage and lower-cost cross-border upgrades.
- Amend their Joint Operating Agreement to improve the processes for new generator interconnections and generation retirements.

The commission also asked for comments on whether persistent M2M payments indicate the need for new transmission and on NIPSCO's and others' estimates of M2M payments. FERC also asked for examples of projects considered but not developed under the cross-border transmission planning process and the reasons why they were not completed.

ISO-NE News

ISO-NE Proposes New Capacity Zones for FCA 10

By William Opalka

ISO-NE has proposed two new capacity zones for Forward Capacity Auction 10 next year (ER15-1462).

The petition filed with the Federal Energy Regulatory Commission on April 6 reflects where the RTO expects transmission constraints to be most severe in the 2019-2020 delivery year. ISO-NE requested that FERC approve the proposed zones by May 29, before the June 1 deadline for qualifying existing capacity and submission of de-list bids.

One new potential zone is Southeastern New England (SENE), a combination of the existing Northeastern Massachusetts/Boston zone with Southeastern Massachusetts/Rhode Island. The other new zone, Northern New England (NNE), is a combination of the existing Maine, New Hampshire and Vermont load zones.

ISO-NE said these are "potential" new capacity zones. "At this phase of the zonal development process, the appropriate boundaries are simply being defined so that if these capacity zones are needed, they can be modeled in the auction," said Alan McBride, director of transmission strategy and services.

No changes are proposed with the current West-Central Massachusetts or Connecticut zones.

SENE is proposed as an import-constrained capacity zone, while NNE is proposed to be export-constrained.

For FCA 9 the zones were: NEMA/Boston, SEMA/RI, Connecticut and Rest-of-Pool, which includes West-Central Massachusetts, Vermont, Maine and New Hampshire.

The RTO conducts an annual assessment of transmission transfer capability to identify system weaknesses as part of its New England Regional System Plan. Modeling showed the effects of recent and pending plant closures, including the Vermont Yankee nuclear plant last year and the 2017 planned mothballing of the 1,535-MW Brayton Point generation station in Massachusetts.

Transmission upgrades planned for eastern Massachusetts will allow power to move more freely within the proposed zone, but constraints were found where the new, larger zone connects to the others. "These constraints are such that new, qualified resources located in either zone would be helpful in addressing the overall constraints. That is, new resources in SEMA/RI would be helpful in unloading the constraints," according to the filing.

In FCA 9, SEMA/RI did not have enough capacity resources bid into the auction. (See *Prices up One-Third in ISO-NE Capacity Auction*.)

In NNE, power flow studies indicate an existing transmission interface is located along the southern borders of New Hampshire and Vermont and the northern border of Massachusetts. Without Vermont Yankee and Brayton Point, "the North-South flows are now forecast to be more concentrated along the lines connecting southeastern New Hampshire with eastern Massachusetts," the RTO said.


The boundary of the proposed Southeastern New England zone would combine the northern and western borders of the NEMA/Boston zone and the western board of the SEMA/RI zone. (Source: ISO-NE)

The Connecticut zone was unchanged due to new resources that entered the zone in FCA 9. (See *Exelon, LS Power Join CPV in Adding New England Capacity*.)

Maxim Seeks Dismissal of Market Manipulation Case

A power generator accused of market manipulation in New England has asked the Federal Energy Regulatory Commission to terminate the case (IN15-4).

Maxim Power on April 6 filed a response to FERC's Office of Enforcement, which last month replied to Maxim's answers to an Order to Show Cause. (See *Fuel-Burn Allegation Meant to Force Settlement of Unrelated Cases, Maxim Says*.)

FERC issued the order in February, accusing the company of billing ISO-NE for oil at its 181-MW plant in Pittsfield, Mass., while actually burning cheaper natural gas during a July 2010 heat wave. In dispute are a series of emails between Maxim employee Kyle Mitton and the Internal Market Monitor.

"Staff's reply contains no credible evidence that Maxim or Mr. Mitton omitted any material fact in any of their communications with the IMM which left the IMM with any false impressions about what fuel actually was burned at Pittsfield," Maxim said.

In its reply, Enforcement said Maxim "made a series of carefully managed statements about pipeline restrictions and the theoretical possibility of losses from offering gas and burning oil, and said nothing about what was actually happening at Pittsfield."

In addition to the Pittsfield plant, Maxim operates two other plants in ISO-NE: CDECCA, a 62-MW cogeneration plant in Hartford, Conn., and Pawtucket Power, a 63.5-MW cogeneration plant in Pawtucket, R.I.

— William Opalka

ISO-NE NEWS

Union: Void ISO-NE Capacity Auction Results

By William Opalka

The union representing workers at the Brayton Point Power Station say the plant's pending closure caused massive price spikes in recent capacity auctions and that the results of the ISO-NE Forward Capacity Auction 9 should be voided (EL15-1137).

Utility Workers Union of America Local 464 filed a protest Monday with the Federal Energy Regulatory Commission seeking to cancel the auction that was held in February for the 2018-2019 capacity commitment period. Comments on the ninth auction were due Monday. (See *ISO-NE Files Capacity Auction Results; Comments due April 13*.)

They charge that the plant's former owner, Energy Capital Partners, removed the 1,510-MW plant in Somerset, Mass., from FCA 8 and FCA 9 to inflate prices offered for other generation plants that it owned. ECP in 2013 said the plant would close in 2017.

"Energy Capital Partners intentionally raised the prices to be paid by purchasers of capacity market-wide in the FCA 8 auction by approximately $1.6 billion to $2.4 billion — an approximately 200% increase over prices in the prior annual capacity auction — and increased market-wide capacity prices by an additional approximately $1 billion in the FCA9 auction," the protest states.

Results at FCA 9 came in at just about $4 billion, $1 billion higher than FCA 8 from February 2014. FCA 8 saw prices triple, to just over $3 billion from the previous year's results of about $1 billion.

UWUA says the "illegal" actions by ECP were a violation of the ISO-NE Tariff. Retirements of generation plants that result in higher prices and profits for the owners' other plants are only allowed if the closed plant was uneconomic on its own.

Brayton Point's sale to Dynegy was announced in 2014 as part of multi-state acquisition of four other plants totaling 1,902 MW. (See *Dynegy Becomes New England Player Overnight*.)

Dynegy reiterated its intention to close Brayton Point immediately after the sale was announced. The union cited a presentation to investors made last summer by Dynegy that said Brayton Point would have operating profits of $105 million in 2015.

The union made a similar protest a year ago when FERC began its review of FCA 8. The results became effective as an operation of law when the commission was deadlocked 2-2. (See *FERC Commissioners at Odds over ISO-NE Capacity Auction*.)

An amended complaint filed by the union in February did not prompt any further commission action (ER14-1409).

FERC last month approved the transfer, saying it had not found credible evidence of the exercise of market power and had already rejected the union's claims. (See *Dynegy Wins FERC OK for $6.25B Duke, Energy Capital Partners Generation Deals*.)

ISO-NE Error Could Cost GenOn Millions

By Rich Heidorn Jr.

The owner of a Massachusetts generating plant says ISO-NE is forcing it to pay unnecessary capacity costs because the RTO mistakenly underestimated the plant's capacity.

GenOn Energy Management, a unit of NRG Energy, asked the Federal Energy Regulatory Commission last week for relief from what it called an "anomalous, illogical and patently unfair circumstance" (EL15-57).

GenOn said ISO-NE credited its Canal 2 oil- and gas-fired generator in Sandwich, Mass., with capacity of only 303 MW — rather than the plant's actual 556.5-MW output — in the March annual reconfiguration auction (ARA) for the 2015-2016 capacity commitment period.

As a result, the RTO submitted a demand bid on GenOn's behalf for the difference, forcing the company "to buy out of a capacity supply obligation that Canal 2 is fully capable of fulfilling." Only a portion of the demand bid cleared because supply offers filled only two-thirds of the demand bids entered.

The company redacted specifics of how much it estimated the error could cost it, but based on the ARA's clearing price of $11.466/kW-month, and the prorated apportionment of cleared bids, GenOn could be forced to spend more than $22 million.

Canal Generating Station (Source: NRG)

GenOn said the plant's output was derated after the failure of a step-up transformer in July 2013, but that it returned to full capacity in May 2014, as documented by the RTO's capacity audits. The company noted that it offered the plant's full capacity in Forward Capacity Auction 9 in February.

The company asked FERC to force the RTO to correct the "obvious mistake on ISO-NE's part" or grant it a waiver to allow it to escape the capacity charges.

It asked for FERC action by May 25 so that ISO-NE can ensure that the appropriate capacity supply obligations are in place before the beginning of the 2015/16 capacity commitment period on June 1.

COMPANY BRIEFS

St. Louis Company Selling Last Two Wind Farms

Wind Capital Group said it is selling its last two U.S. wind farms to a California company. Wind Capital said it will sell the 150-MW Lost Creek wind farm in Missouri and the 210-MW Post Rock facility in Kansas to San Francisco-based Pattern Energy Group. Wind Capital said the sales, for a reported $244 million, will allow it to focus on its wind developments in the United Kingdom and Ireland.

More: *St. Louis Post-Dispatch*

Entergy Spending $62.2M on 24-mile Tx Line in Arkansas

Entergy Arkansas said it is spending $62.2 million to build a transmission line and a new substation to improve grid reliability in Drew and Desha counties. The company said it is part of a $2.4 billion investment through 2017 on system upgrades. It is already constructing another 27-mile transmission line that will end at the same new substation. That project is estimated at $25 million.

More: *Magnolia Reporter*

Duke Finds Hairline Crack On Reactor Head at Harris Plant

Duke Energy Progress discovered a hairline crack in the reactor pressure head of Shearon Harris nuclear generating station, but the company told the Nuclear Regulatory Commission that the crack poses no danger. The crack will be repaired during the current refueling outage, the company said. "The unit is in a safe and stable condition," Duke told NRC. "The flaw and repair have no impact to the health or safety of the public."

The crack, measuring about a quarter-inch, is near a nozzle that penetrates the reactor head. It is similar to a crack that was missed during a 2012 refueling inspection and caught later during a data review. After that incident, NRC ordered Duke to ensure such an incident didn't happen again.

More: *Charlotte Business Journal*

NextEra Bets Big On Colorado Wind

NextEra Energy Resources is investing $640 million on two more wind farms in Colorado. The company already has invested about $2 billion on seven Colorado wind farms generating about 1,175 MW. The company said the two new wind farms should be ready to come online by the end of the year.

The first facility, a $240 million 150-MW wind project in Kit Carson County, has a 25-year contract to sell its output to Tri-State Generation and Transmission Association. The second facility, the $400 million 250-MW Golden West Wind energy Project, will be in El Paso County and will sell its output to Xcel Energy.

NextEra is the largest wind farm operator in the U.S., with 10 GW of turbines.

More: *Denver Business Journal*

E.ON Starting Asset Management, Repair Businesses in US

E.ON, the world's largest investor-owned utility, is branching out into the asset management and facility repair business in the United States. The company owns or operates nearly 3 GW of generation in North America, and now it's starting up E.ON Energy Services. The new business will offer on-site repair and asset management operations for plants it does not own. "As we transitioned to an operations-focused company several years ago, we saw a large growing demand for qualified service providers," E.ON's North American chairman Patrick Woodson said. He pointed to the continent's growing wind and solar industries as an area where the company could expand.

More: *pv magazine*

Advanced Power Gets Funding For $899M Combined-Cycle Plant

Advanced Power, based in Switzerland, has closed financing for an $899 million combined-cycle plant it will build in northeastern Ohio. The 700-MW natural gas-fired plant will sell energy, capacity and ancillary services into the PJM market. Advanced Power secured $411 million in funding from TIAA-CREF, Ullico and Prudential Capital Group, and a further $488 million from BNP Paribas, Credit Agricole and eight other banks. The Carroll County Energy Project will be in Carrollton, Ohio, close to both the Utica and Marcellus shale gas fields, as well as American Electric Power's 345-kV transmission line.

The company did not say when construction would begin.

More: *Dayton Business Journal*

Duke Appeals $25 Million Ash Fine, Calls it Excessive

Duke Energy is appealing a $25.1 million fine levied by North Carolina environmental officials in connection with groundwater pollution from ash piles at a retired power plant. Duke says the fine is excessive and that it has taken corrective action.

The state Department of Environment and Natural Resources fined the Charlotte, N.C.-based company in March for failing to control ground water leaching from the coal ash lagoons at the now-retired L.V. Sutton Steam Electric Plant near Wilmington, N.C.

The fine is separate from a $102 million settlement the company agreed to pay federal authorities for the damage caused by a massive leak of toxic coal ash from another retired plant, near the Dan River. That event last year caused pollution in two states — Virginia and North Carolina — after a broken pipe allowed coal ash slurry to flow into the river. The company still faces litigation from Virginia and private property owners as a result of that leak. North Carolina, in response, enacted coal-ash legislation and formed a formal oversight committee.

Duke's appeal of the Sutton fine notes that the company had already taken corrective actions to stop and remediate the leakage from the retired plant. It also claims that state environmental officials erred in fining the company for 1,822 days of violations, despite only taking samples for 27 days, using a new way of calculating the fine, making it $24 million higher than fines for earlier, similar events, and failing to take into account the possibility of other sources of contamination.

More: *News & Record*

-- Compiled by Ted Caddell

FEDERAL BRIEFS

High Court to Consider Demand Response Challenge April 24

The U.S. Supreme Court will consider the Federal Energy Regulatory Commission's appeal of a ruling voiding its authority over demand response in its conference April 24. At least four of the nine justices must agree to hear the case (14-840) for it to proceed.

FERC filed a petition for a writ of certiorari in January, contending that the D.C. Circuit Court of Appeals erred in its 2014 ruling (*Electric Power Supply Association v. Federal Energy Regulatory Commission*) that FERC lacked authority under the Federal Power Act to regulate energy market payments to DR providers.

The ruling, which voided FERC Order 745, was limited to the energy markets. But some stakeholders say the ruling also invalidates the commission's regulation of DR in capacity markets. On March 31, FERC rejected as premature PJM's proposed contingency plan for including demand response in its May Base Residual Auctions in the event the D.C. Circuit's ruling is allowed to stand. (See *FERC: PJM Demand Response Stop-gap Measure 'Premature'*.)

More: *14-840*

Wisconsin Energy Takeover of Integrys Gets OK from FERC

The Federal Energy Regulatory Commission on April 7 approved Wisconsin Energy Corp.'s $9.1 billion acquisition of Integrys Energy Group.

Wisconsin Energy is the parent of electric utility We Energies. Integrys owns the Green Bay-based electric-natural gas utility Wisconsin Public Service Corp., along with Peoples Gas.

FERC dismissed concerns raised by a consortium of municipal electric utilities that contend that the merged companies would have undue influence over American Transmission Co., noting the new Wisconsin-based utility giant plans to limit voting rights in ATC.

The deal still requires the approval of four states: Wisconsin, Michigan, Minnesota and Illinois.

More: *Milwaukee Journal Sentinel*

Feds Consider Rules that Would Protect Bats, Hobble Wind Farms

The U.S. Fish and Wildlife Service is studying whether it needs to modify some rules protecting the Northern long-eared bat in a move that could affect wind farms. The agency announced that it would list the species as threatened.

The designation could result in regulations increasing the wind speed at which turbines are allowed to start producing energy on the theory that fewer bats will be flying when wind speeds are high. The agency is taking comments on the proposed rule changes and is expected to finalize the rules by the end of the year.

More: *Midwest Energy News*

NRC Approves Use of Hotter Fuel Rods at FirstEnergy's Perry Plant

A new type of fuel rod that has thinner metal walls encasing enriched uranium has been approved for use at FirstEnergy's Perry nuclear generating station. The Nuclear Regulatory Commission has approved the use of the fuel rods, which should result in an increase of energy production while allowing use of less enriched uranium.

FirstEnergy is replacing about a third of the 748 fuel rod assemblies during the current refueling outage. Opponents to the plan say that the thinner fuel rod walls could present a problem moving the fuel rods in the decades to come after the rods are exhausted. NRC is currently testing the rods for long-term storage issues.

More: *The Cleveland Plain Dealer*

Group Says RGGI Could Be Way to Meet Emissions Mandates

A New England nonprofit energy policy group has released a report that says joining the Regional Greenhouse Gas Initiative could provide a solution for Virginia to meet upcoming federal emission reduction mandates. The Acadia Center said that by joining the nine states already participating in RGGI, Virginia could have a "plug-and-play" way of satisfying the requirements of the Environmental Protection Agency's Clean Power Plan.

"Virginia could build on this existing foundation by adopting the RGGI model rule, which would allow the commonwealth to participate in the market while preserving authority and enforcement at the state level," according to the report.

It isn't clear how much support such a move would have in Virginia. A bill calling for Virginia to join the RGGI never got past committee earlier this year in Virginia's Republican-controlled legislature.

Nine states currently participate in the RGGI: New York, Maryland, Massachusetts, Maine, Delaware, New Hampshire, Rhode Island, Connecticut and Vermont. New Jersey was a member, but Gov. Chris Christie pulled the state out two years ago.

More: *Acadia Center*

PPL Gets Approval for Transfer Of Nuclear Asset to Talen

The Nuclear Regulatory Commission has approved the transfer of PPL's Susquehanna Steam Electric Station nuclear plant operating licenses to a new merchant generation company, Talen Energy. PPL is spinning off most of its generation, which will be combined with assets owned by Riverstone Holdings, to form Talen. The new company will be an unregulated, competitive generation supplier. Allegheny Electric Coop. has a minority ownership share of the two-unit plant.

The Federal Energy Regulatory Commission and the state Public Utility Commission have approved various filings relating to the Talen spinoff. Final approval is still needed from the U.S. Department of Justice under the Hart-Scott-Rodino Antitrust Improvements act. PPL still says it expects to close the transaction by the end of June.

More: *PPL*

-- Compiled by Ted Caddell

State Briefs

ILLINOIS

ComEd Smart Grid Bill Becomes Law

Republican Gov. Bruce Rauner has approved a bill allowing Commonwealth Edison and Ameren Illinois to avoid legislative review of a sweeping grid modernization program until 2019 instead of 2017.

Critics, including the Citizens Utility Board, worry that the move will allow the utilities to increase electric rates without being held accountable enough for their performance.

The bill passed both houses last year with bipartisan support, and Senate President John Cullerton (D-Chicago) waited to send it to the governor's office until outgoing Democratic Gov. Pat Quinn, historically a utility antagonist, left office.

More: *Chicago Tribune*

KANSAS

KCC Orders Reduction of Wastewater Injection

The Corporation Commission has ordered a reduction in the amount of drilling wastewater injected into deep disposal wells in light of a report linking the injections with earthquakes. The order relates to two counties bordering Oklahoma, which has experienced an increase in seismic activity apparently related to the disposal of wastewater produced from oil and gas wells.

"Because individual earthquakes cannot be linked to individual injection wells, this order reduces injection volumes in areas experiencing increased seismic activity," the order states. "The commission finds increased seismic activity constitutes an immediate danger to the public health, safety and welfare. The commission finds damage may result if immediate action is not taken."

The commission cited a study by the U.S. Geological Survey that showed an increase in the number of earthquakes corresponded with an increase in wastewater disposal. There were 30 earthquakes in Kansas between 1981 and 2000. In the first three months of this year, there have been 51 recorded earthquakes.

More: *EcoWatch*

MARYLAND

Wind Project Dies in Face Of Air Station Concerns

A Somerset County wind project has been scrapped after the developer tired of opponents who feared the wind turbine towers would endanger Naval Air Station Patauxent River. Pioneer Green Energy notified county authorities that it was withdrawing the plan, which would have built 25 turbines producing up to 150 MW.

State lawmakers pushed through a 15-month moratorium on the $200 million development, which then-Gov. Martin O'Malley vetoed. U.S. Sen. Barbara A. Mikulski pushed through a measure halting the project amid concerns that the turbine towers would interfere with the air station's radar system. More legislation blocking wind development across the Chesapeake Bay on the Eastern Shore is brewing, with opposition growing against a planned 130-MW wind project near Kennedyville in Kent County. In view of the opposition, Adam Cohen, vice president of Pioneer Green Energy, decided to surrender. "We are truly saddened we cannot bring new investment, jobs and tax base" to Somerset County, he wrote to county officials.

More: *The Baltimore Sun*

MINNESOTA

Minnesota Power, State Reach Agreement on SO2 Releases

Minnesota Power reached an agreement with the Pollution Control Agency concerning sulfur dioxide emissions at its Taconite Harbor Energy Center in Schroeder. The 225-MW, coal-fired plant was the focus of attempts by environmental groups to force Minnesota Power to reduce emissions. The plant has been operating under a decade-old permit.

Minnesota Power has struggled to bring the plant into compliance and announced the closing of one of the three boilers this year. It also installed emissions-control technology, but it has not performed as expected. In addition to retiring one unit, the company will also pay a $1.4 million fine and spend $4.2 million on community projects. It will also need to submit a plan to the Public Utilities Commission that will outline what steps are being taken to reduce emissions further.

More: *Midwest Energy News*

MISSOURI

Supreme Court Rules Empire Must Offer Solar Rebates to All

Empire District Electric must offer all eligible customers solar rebates, the state Supreme Court has ruled. The court found that a state law exempting Empire from Missouri Clean Energy Act requirements was unconstitutional. The ruling spurred Renew Missouri, a clean energy advocacy group, to file a motion with the Public Service Commission to compel Empire to file an official tariff offering solar rebates by April 15. "Our hope is that Empire responds by immediately offering rebates," said P.J. Wilson of Renew Missouri. "Their customers have been waiting since January 2010, the date Empire was required by law to start offering solar rebates. Today, the waiting should finally be over."

The case came to the state's high court as a result of developments dating back to 2007, when the state's Renewable Energy Standard was passed. That standard called for utilities to get 15% of their energy from renewable sources by 2021 and to offer rebates to customers who wanted to install solar panels. But in 2008, lawmakers passed H.B. 1181, which exempted Empire from solar requirements. Renewable proponents challenged the law in court.

More: *The Joplin Globe*

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STATE BRIEFS

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NEW JERSEY

BPU Considering Request by New Jersey Natural Gas for Pipeline

New Jersey Natural Gas has filed a proposal with the Board of Public Utilities to build a 28-mile natural gas pipeline through three counties. If approved, the 30-inch pipline would start in Burlington County and run through Monmouth and Ocean counties. The proposed $130-million project, called the Southern Reliability Link, is designed to be a redundant line in the event an existing pipeline in Middlesex County is disrupted.

Already the plan is attracting opponents, who have previously organized against another project the company is involved with, the PennEast project. That proposed pipeline, which would run 110 miles from eastern Pennsylvania to Mercer County, has been the focal point of major opposition from community and environmental groups in both states. Some environmentalists note that the Southern Reliability Link is routed to go through federally protected pinelands. The first public hearings on the project have not yet been scheduled by the BPU.

More: NJ.com

NORTH CAROLINA

Bill Would Allow Third-Party Leasing for Solar Installations

A Republican-backed bill would allow independent third-party energy companies to sell directly to homes and businesses. While the bill will likely attract opposition from utilities, the legislation would benefit solar developers. Major corporations are being enlisted to support the bill, which would allow independent companies to lease solar installations to home and business owners, and then sell the power produced directly to the owners, cutting out the utilities entirely. Wal-Mart, Target and Lowe's have contacted House Speaker Tim Moore to support the bill, called the Energy Freedom Act.

"I'm coming at this from a Republican viewpoint," said bill sponsor Rep. John Szoka of Fayetteville. "I believe in free markets and I believe in property rights. This allows property owners to use their property as they see fit."

The state is already the nation's fourth largest solar producer.

More: The News & Observer

NORTH DAKOTA

State to Study Effects of Clean Power Plan

While the U.S. Environmental Protection Agency has released studies showing the probable impact of the rules of the Clean Power Plan on the nation, none of those studies get down to the state and local level. North Dakota hopes to change that by ordering a study that will examine the expected effects of the Clean Power Plan on natural gas prices, electricity rates and renewable energy production in the state. Gov. Jack Dalrymple signed a bill authorizing a study of the rules, which are expected to take effect this summer. Jason Bohrer, president of the Lignite Energy Council, said the study will look at the financial implications of the federal rules.

More: The Bismarck Tribune

OHIO

PUCO Denies Duke's Guarantee Return Scheme

The Public Utilities Commission turned down Duke Energy's request that it receive a ratepayer-guaranteed return for its share in two older coal-fired generation plants, rejecting the company's argument that the arrangement would have provided long-term price stability for customers. PUCO in February denied a similar request by American Electric Power.

FirstEnergy has a similar request pending before the commission, and AEP has a request concerning other plants it says are at risk of closing if they are not guaranteed prices. The most recent decision involved the coal-fired plants owned by the Ohio Valley Electric Corp. OVEC's shares are owned by Duke, AEP and FirstEnergy, among other companies. If PUCO had approved Duke's request, its Ohio utilities would have purchased power from the plants at a long-term contract and then passed that price on to customers. Opponents have called the arrangements bailouts for the generating companies.

More: Midwest Energy News

Gov. Kasich Names Porter As Chairman of PUCO

Porter

Andre Porter, a 35-year-old Republican and former member of the Public Utilities Commission who stepped down from the state Department of Commerce to rejoin it, was named PUCO chairman by Gov. John Kasich. Porter's five-year term begins this week. He replaces Tom Johnson, who announced his resignation as chairman earlier this month. Johnson will fill out his term as one of the five members of the commission. Porter was widely seen to be Kasich's choice when Johnson resigned.

More: The Columbus Dispatch

OKLAHOMA

AG Urges OCC to Drop Mustang Replacement from OG&E's Plan

The state Attorney General's office said Oklahoma Gas and Electric has not provided enough information about its planned replacement of the aging Mustang power plant to justify its request for $344 million in replacement costs. An assistant attorney general requested that the Corporation Commission drop the Mustang replacement request from the company's $1 billion rate case. The company, however, disagrees. "There is a huge record in this case, and much of it is related to Mustang," said Bill Bullard, an attorney for OG&E. If all of OG&E's rate case is approved, it would increase the average residential customer's bill by about 15%. The plan would replace the aging units with seven 40-MW combustion turbines.

More: The Oklahoman

PENNSYLVANIA

PECO, PPL Ask PUC Approval To Boost Fixed Customer Charges

PECO and PPL Electric have filed requests with the Public Utility Commission that include substantial increases in the basic monthly customer charges. PECO asked to increase its monthly customer charge 68%, from $7.13/month to $12. PPL wants to increase its monthly rate from $14.13/month to $20, a 42% increase. The charges

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STATE BRIEFS

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remain the same no matter how much electricity the customer uses. Both companies say they want to raise the charges to fund maintenance and upgrade costs for their electric distribution systems. In PECO's case, the new charges would result in $84.5 million in revenue, almost half of the $190 million of its overall rate hike request.

Consumer advocates are crying foul, though. "It's poor public policy," said Bill Malcolm, a senior legislative representative for AARP. "Raising the fixed monthly charge lowers the variable per-kilowatt charge, which creates a disincentive for conservation and energy efficiency and gives consumers less control of their bill." Others say the fixed rates strip away any incentive to reduce power usage. "It gives consumers less control of their bill because more of their bill is fixed and not based upon their usage," acting Consumer Advocate Tanya McCloskey said.

More: The Philadelphia Inquirer, CBSPhilly

Some Electricity Users to See Rate Hikes

Customers of Pennsylvania Electric and Pennsylvania Power will pay more for electricity beginning next month — about 13% more for Penelec customers and 7% for Penn Power customers.

The increases are part of rate settlements approved last week by the Public Utility Commission for FirstEnergy's four state subsidiaries: Penelec, Penn Power, West Penn Power and Met-Ed.

The rate hikes are lower than what FirstEnergy originally requested last August. The increases in the base distribution rates are effective May 19 and are the first for each of the four subsidiaries in at least 20 years, according to the PUC.

More: *The Meadville Tribune*

VIRGINIA

Duke Agrees to $2.5M Settlement over Dan River Ash Spill

Duke Energy has agreed to a $2.5 million settlement with state environmental officials to offset damage caused when 39,000 tons of toxic coal ash from a retired power plant spilled into the Dan River. The company has reached a $102 million settlement with federal authorities and was fined $25 million by North Carolina in connection with the spill, which fouled 70 miles of the Dan River. The Department of Environmental Quality said $2.25 million will fund environmental projects in communities affected by the spill, and the remaining $250,000 will be retained for a DEQ environmental emergency fund. Danville, perhaps the hardest hit of the communities, is still negotiating with Duke over the spill.

More: *The New York Times*; *Department of Environmental Quality*

WISCONSIN

Workers Banned from Using 'Climate Change'

Adamczyk

The three-member Board of Commissioners of Public Lands has enacted a state ban on its employees using the term "climate change." The reasoning, according to State Treasurer and Republican Matt Adamczyk: Climate change is "not part of our sole mission, which is to make money for our beneficiaries. That's what I want our employees working on. That's it. Managing our trust funds."

The term "climate change" must not enter into that specific conversation, Adamczyk and Attorney General Brad Schimel, the other Republican sitting on the board.

"Having been on this board for close to 30 years, I've never seen such nonsense," said the third member, Democrat and Wisconsin Secretary of State Doug La Follette, who voted against the measure. "We've reached the point now where we're going to try to gag employees from talking about issues. In this case, climate change. That's as bad as the governor of Florida recently telling his staff that they could not use the words 'climate change.'"

More: *Bloomberg Business News*

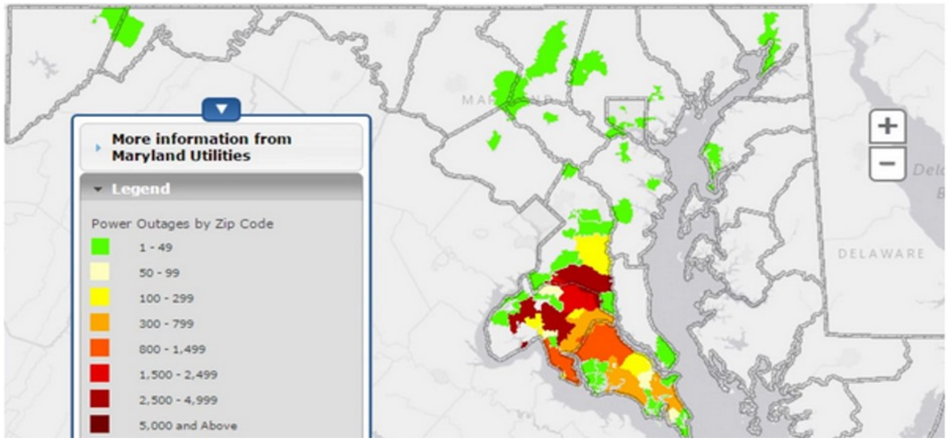
-- Compiled by Ted Caddell

In case you missed it ...

(Originally published April 9)

PJM, Utility Officials Investigating Cause of DC-Area Outage

By Suzanne Herel



Outages hit much of southern Maryland. (Source: Maryland Emergency Management Agency)

PJM and utility officials said yesterday they are still investigating what caused the failure of a 230-kV transmission line that briefly cut power to the White House and much of the D.C. area Tuesday afternoon.

The incident caused a drop in voltage that led the Calvert Cliffs nuclear units to trip offline and federal agencies and other customers to transfer to their backup systems.

The incident occurred around 12:40 p.m. after a fault on a 230-kV transmission line in southern Maryland, PJM's Chris Pilong told the Market Implementation Committee on Wednesday. Pilong said the failure was believed the result of "failed insulation."

The Southern Maryland Electric Coop. said the incident occurred at the Ryceville substation in Charles County when the PEPCO conductor "broke free from its support structure and fell to the ground." The station is jointly owned by PEPCO and SMECO.

"No other outside influences are expected," Pilong said. "It was just a fault, a failed insulator."

Maintenance Outage

Pilong said the incident occurred while several 230-kV lines in the area were out of service for planned maintenance and that the problem was exacerbated by a stuck breaker. Three remaining 230-kV lines and a 500-kV bus were lost, and the fault and voltage drop "rippled" to surrounding substations, he said.

SMECO said the failure cut power to its Ryceville and Hewitt Road stations as well as PEPCO's supply to the Morgantown and Chalk Point interconnections. "No SMECO equipment was damaged and all protective devices operated correctly to isolate SMECO equipment from the PEPCO fault," it said.

The grid recovered — returning its area control error to normal bounds — in about seven minutes, Pilong said.

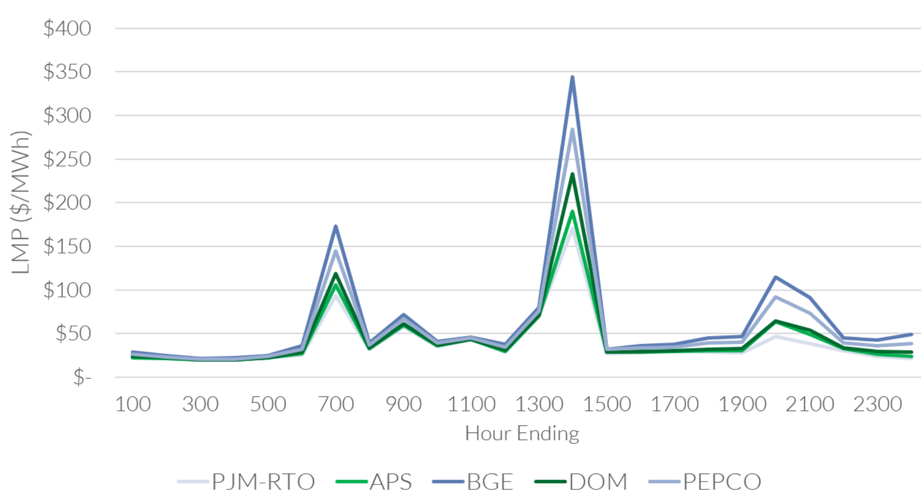
The outage trapped people in elevators, darkened D.C.'s subway stations and caused some institutions — including a Department of Energy building, the main campus of the University of Maryland and some Smithsonian museums — to shut down for hours, *The Washington Post* reported.

Wholesale Prices Spike

In addition to causing disruptions to consumers and businesses, the incident resulted in a spike in wholesale prices, with real-time LMPs in the BGE zone rising from less than $38 at noon to more than $344 for the 1-2 p.m. hour. The other zones most affected were DOM, PEPCO and APS (see chart).

Initially, it was thought that up to 500 MW might have been lost, but later it was determined that customers had switched to off-grid power. About 300 MW returned to the grid within 40 minutes, PIlong said. By late afternoon, only the line that was the source of the fault was out of service.

"There was never a loss of permanent supply of electricity to customers," PEPCO said.



The Pepco outage was followed by a spike in prices. (Source: PJM)

Calvert Cliffs

Exelon, which operates the Calvert Cliffs units, said the plant shut down automatically as designed during significant electrical disturbances. However, Exelon told the Nuclear Regulatory Commission it is investigating why an emergency diesel generator serving Unit 2 did not start.

"Both reactors will remain in 'hot shutdown,' which means the reactor remains ready to resume power production, until the offsite grid disturbance can be addressed," Exelon said.

As of Wednesday evening, the NRC still listed output at Units 1 and 2, which have a combined capacity of 5,474 MW, as zero.

In case you missed it ...

(Originally published April 7)

Divided FERC Trims ROE on NY Tx Projects, Orders Hearing

By William Opalka

Five transmission projects intended to serve New York City and respond to a potential nuclear plant closure suffered setbacks last week as a divided Federal Energy Regulatory Commission rejected the developers' cost allocation proposals and reduced their requested returns on equity (ROE).

The commission granted some of the developers' requests for ROE incentives but ordered settlement and hearing proceedings on proposed formula rates, protocols and the base ROE (ER15-572).

On Dec. 4, NYISO proposed a cost-of-service formula rate template and formula rate implementation protocols on behalf of New York Transco, comprised of affiliates of the New York Transmission Owners, Consolidated Edison of New York, National Grid, Iberdrola USA and Central Hudson Gas & Electric.

The companies submitted five projects in response to competitive solicitations issued by the New York Public Service Commission.

Two AC projects, the estimated $1 billion Edic-Pleasant Valley 345-kV line and the $246 million Oakdale-Fraser 345-kV line, are intended to alleviate congestion on transmission lines serving the New York metropolitan area. (See *Tx Plan to Open NY Choke Points Without New ROWs*.)

The other three "Transmission Owner Transmission Solutions (TOTS)" projects were designed to address reliability concerns expected if the Indian Point nuclear plant closes. NYISO and the transmission owners sought an April 3 effective date on their proposed formula rate, protocols, cost allocations and 10.6% base return on equity.

The commission:

- Granted requests for construction work in progress, abandonment and pre-commercial cost recovery incentives, and a 50-basis-point ROE adder for membership in an RTO, subject to a cap within the "zone of reasonableness," to be established through the hearing procedures.
- Approved an ROE adder for risks and challenges for the Edic-Pleasant Valley 345-kV line while rejecting it for the Oakdale-Fraser 345-kV line and the TOTS projects.
- Ordered the applicants to revise sections 3(e)(ix) and 4(b) of the formula rate protocols, as requested by the New York Association of Public Power, to provide more transparency. The commission said it was concerned with the allocations of shared plant or expense items between members of NY Transco and their parent companies.
- Rejected the cost allocation for all five projects.
- Denied applicants' request for an ROE adder for being a transmission company. The commission said NY Transco's members were not "sufficiently independent" to merit incentives, noting that they serve 84% of the state's load and own 64% of its high voltage transmission and 4% of its generation capacity.
- Ordered hearing and settlement procedures on NY Transco's proposed formula rates, protocols and base ROE, including components of the formula rate and the allocation of various expenses between the TOs and NY Transco. The commission ordered appointment of a settlement judge within 15 days and a report on the status of negotiations by May 4.

Dissents on Capital Structure

The majority also rejected applicants' request for a "hypothetical" capital structure incentive of 60% equity and 40% debt for all five projects, instead approving a 50/50 structure.

NY Transco said it would use its actual capital structure in the formula rate after the projects are placed into service but that the hypothetical capital structure would improve its credit rating, reducing financing costs by $168 million compared with a 50/50 structure.

The majority said it agreed with protests by the PSC and others that the 60/40 capital ratio is "excessive for an entity such as NY Transco, whose affiliates ... will construct the projects and perform the maintenance and physical operation of the NY Transco assets."

That sparked a partial dissent by FERC Chairman Cheryl LaFleur and Commissioner Philip Moeller. "Today's order does not merely apply an overly rigid approach to evaluating these capital structures; the majority has failed to provide any criteria or guidance as to how the commission will evaluate these capital structures going forward," they wrote. "We believe the applicants demonstrated the required nexus between the need for the requested hypothetical capital structure and the facts of this particular case, and we would have granted the requested transmission incentive."

LaFleur and Moeller also said the additional proceeding adds "needless uncertainty" to efforts to expeditiously build transmission infrastructure.

Cost Allocation

The commission rejected the cost allocation method for the AC and TOTS projects because it imposed costs on the New York Power Authority and the Long Island Power Authority, both public entities that have not been allowed to join NY Transco.

The PSC said the cost allocation proposal it initially supported included the voluntary participation of LIPA and NYPA, and covered 18 transmission projects throughout the state. NY Transco was originally planned as a six-party Transco, which included NYPA and LIPA, but the New York state legislature refused to allow NYPA permission to participate.

NYPA serves municipal systems throughout the state, but NY Transco's cost allocation proposal would have assessed its municipals located upstate at the same rate as downstate municipals. "Grossly inequitable situations would arise where a NYPA customer located in the Rochester region would be allocated 16.9% of the costs while another [Rochester Gas & Electric] customer located across the street ... would be allocated only 8.9% of the costs," the commission said.

Because NYPA and LIPA have not accepted the cost allocation method, it cannot be considered a "participant funding method," the commission said.

The applicants had proposed to allocate the costs of the three TOTS projects using an adjusted load ratio share approach, with 75% of the costs allocated to transmission districts southeast of the UPNY/SENY constraint and 25% allocated to upstate districts, a departure from the default ratio for

Continued on page 25

In case you missed it ...

(Originally published April 7)

Divided FERC Trims ROE on NY Tx Projects, Orders Hearing

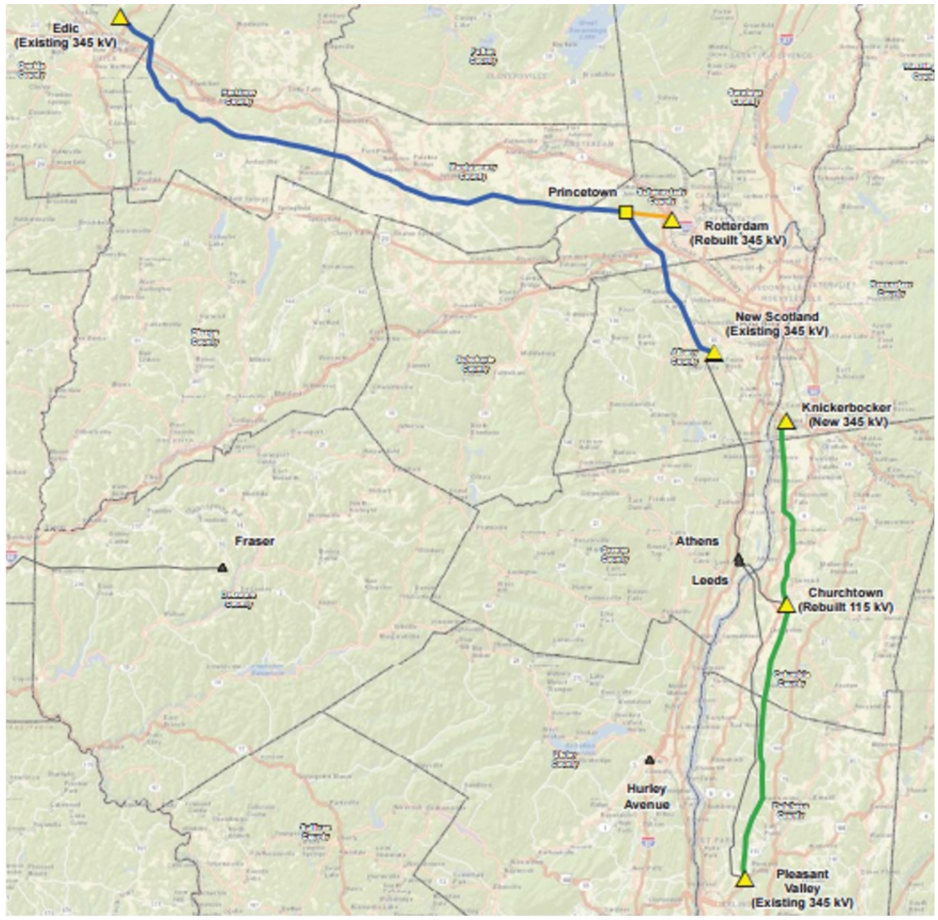
Continued from page 24

public policy projects (60% downstate, 40% upstate). The PSC adopted a 90% downstate/10% upstate cost allocation for the AC projects.

The commission said the AC projects could qualify for regional cost allocation if the PSC decides they should be evaluated under NYISO's Order 1000 public policy transmission planning process and the ISO selects the projects in the regional transmission plan.

Because the TOTS projects were evaluated by the PSC before NYISO's Order 1000 transmission planning process, the ISO must reevaluate and select them to be eligible for regional cost allocation, the commission said.

Alternatively, the commission said the applicants may submit a revised allocation shared only by entities that agree to pay, "either by renegotiating the cost allocation with LIPA and NYPA or by allocating the costs solely among those transmission developers participating in the NY Transco."



Edic-Pleasant Valley 345-kV Project (Source: National Grid)

AC Projects

The commission said the 153-mile, Edic-Pleasant Valley 345-kV line deserved a risk-reducing incentive because it would relieve transmission congestion on existing lines by 41% in 2022.

The project would connect National Grid's Edic substation in Oneida County to Con Edison's Pleasant Valley substation in Dutchess County, entirely within existing rights-of-way. The project, including three new substations, would move an additional 1,000 MW from central New York to the southeast region. The line is expected to reduce transmission congestion costs, line losses and installed capacity costs by a net present value of almost $1.3 billion to $4.5 billion over 10 years.

The commission rejected such a bonus for the Oakdale-Fraser 345-kV project, saying it was not convinced it relieved "chronic and severe congestion." The project would add a second, 57-mile 345-kV line between the Oakdale and Fraser 345-kV substations.

The three TOTS projects were approved by the PSC as a contingency plan for the loss of Entergy's Indian Point nuclear plant. The projects, which have an in-service deadline of June 1, 2016, are the:

- Fraser-Coopers Corner project, estimated at $66 million, which will increase power transfer by reducing series impedance over the existing 345-kV Marcy South transmission lines;
- Ramapo-Rock Tavern project ($121 million), which will add a second 345-kV line from Con Edison's Ramapo 345-kV substation to Central Hudson's Rock Tavern 345-kV substation; and
- Staten Island Unbottling Project ($262 million), which involves transmission upgrades to Con Edison's interconnecting 345-kV transmission line with Cogeneration Technologies Linden Venture, to allow generating facilities located on Staten Island to export power to the rest of New York.

PJM Responds to FERC Queries on Capacity Performance, Requests Approval

Continued from page 1

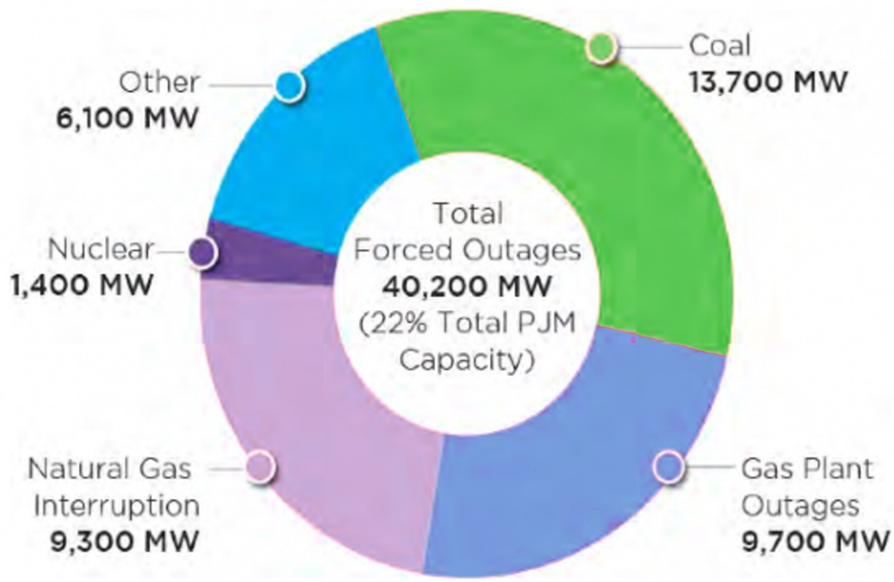
FERC's March 31 order deeming its Capacity Performance filing deficient, it expedited the reply in hopes it can avoid having to postpone the BRA — something it has never done. However, because of the uncertainty surrounding the new Capacity Performance product — and because the Tariff requires the auction be held in May — the RTO last week requested a waiver to delay the BRA. (See PJM to Respond on Capacity Performance Friday; Seeks Auction Delay.)

PJM said that if FERC does not respond to the waiver request by April 24, the RTO will consider it withdrawn. Meanwhile, it is advising stakeholders to prepare for the auction to be held as scheduled May 11-15.

FERC's four-page order questioned 10 areas of the proposal, which was conceived to increase reliability expectations of capacity resources with a "no excuses" policy (*ER15-623*). PJM's proposal called for larger capacity payments for over-performing participants and higher penalties for non-performers.

FERC asked PJM to explain its derivation of an appropriate competitive clearing price when no new capacity is required in a locational deliverability area (LDA), and to provide more detail on a default offer cap and how it would apply in several situations.

Causes of Forced Outages Jan. 7, 2014



(Source: PJM Interconnection LLC)

PJM responded in detail, saying "a default Capacity Performance resource offer cap, based on net [cost of new entry] times the balancing ratio, is reasonable and appropriate."

PJM introduced the balancing ratio to adjust a resource's committed unforced capacity (UCAP) to reflect its expected performance during Performance Assessment Hours. The proposed ratio would be calculated by dividing total load and reserves on the system by total generation and storage capacity commitments during the Performance Assessment Hour. Regarding concern raised by some interveners that the balancing ratio is too difficult to estimate in advance, PJM said that if the commission accepts the offer cap agreed upon by PJM and the Independent Market Monitor, it will use a historical weighted average based on the previous three delivery years. During that period, there were 70 hours — including 42 hours of RTO-wide emergency — that would have been Performance Assessment Hours.

"Capacity Performance provides extremely strong incentives for resource availability and therefore, over time, will eliminate occurrences like those seen in the winter of 2014," PJM said. "As a result, the expected value of the balancing ratio is anticipated to increase over time to a value that is more indicative of the summer Performance Assessment Hours, which averaged around 93.5%."

FERC also requested any analyses the RTO had conducted on expected performance charges and bonus payments under the proposal. The commission asked if it made sense to phase in the penalties and for ideas of how to provide incentives for resource performance. In addition, it asked PJM how it plans to evaluate the performance of external resources not pseudo-tied to the RTO.

PJM cited the transitional structure it proposed in the plan that would allow PJM and capacity market sellers to adjust to the new product over the two remaining delivery years before 2018/19.

"As such, PJM therefore believes that it is unnecessary to provide further transition into the Capacity Performance structure from the standpoint of the non-performance charge, because load should be assured that Capacity Performance resources have the full incentive to invest appropriately in their resources from the 2018/2019 delivery year forward," it said. "Phasing in the non-performance charge rate beyond what PJM has already proposed in its transition mechanism would inappropriately dilute this incentive."

RTO Insider

Editor & Publisher: Rich Heidorn Jr.
Marketing & Operations: Merry Eisner

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 983-0375

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