Energy Choice Matters

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New York TOs Slam NYISO Handling of System Modeling Error

FERC should not grant a waiver requested by the New York ISO, which NYISO sought to avoid retroactively changing prices or settlements due to a system modeling error, until a stakeholder process is convened to further consider the root cause of the error and the impacts on market prices, the New York Transmission Owners (TOs) said in comments at FERC (ER09-405).

On December 11, NYISO submitted a filing to notify FERC of a system modeling error in its Security Constrained Unit Commitment (SCUC) software that affected certain day-ahead market schedules and prices, and to request a limited waiver of the tariff provisions implicated by the system modeling error, so that the NYISO will not be required to retroactively change prices or settlements.

The New York Transmission Owners are "troubled" by the length of time that the NYISO took to notify market participants of the modeling error, and the absence of stakeholder involvement in the analysis of the error and the development of corrective actions. While the NYISO recognized the error, analyzed its impact and took steps to correct it, the ISO did not notify market participants for almost an entire year, the six TOs said. Given the amount of time that has elapsed between the occurrence of the tariff violation and the implementation of the NYISO's corrective actions which purportedly addressed the issue, there is no immediate need to grant the NYISO's request, TOs said.

Rather, the NYISO should provide further information before any waiver is considered, including a detailed analysis of the impact of the error on various aspects of the NYISO's market, including energy prices, Transmission Congestion Contracts (TCC) payments and congestion revenue allocations, TOs recommended.

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AEP Proposed Ban on PJM Load Response Meant to Boost Off-System Sales, Integrys Marketer Says

"Other than the unwanted impact of competition on AEP's shareholder profits," AEP Ohio has no reasonable basis for its request to limit bundled customers' participation in PJM demand response programs, Integrys Energy Services said in a post-hearing brief on AEP's Electric Security Plan.

"Simply put, the Companies seek to ban participation by their customers in the PJM programs because the PJM programs are more beneficial to the retail customer than participation in the Companies' proposed demand response programs," the Integrys marketer argued.

"Rather than compete by offering a better program, the Companies seek to have the Commission compel customers to participate in their inferior programs," Integrys Energy Services noted.

"Further, the Companies then plan on selling the capacity and energy freed up by its programs into the PJM markets without sharing the revenues with their retail Ohio customers, for the benefit of the Companies shareholders," Integrys Energy Services charged.

Participation in AEP Ohio's current demand response programs have been meager, with only six customers at Ohio Power and one customer at Columbus Southern Power enrolled in the utility-offered interruptible service schedule (Schedule IRP-D). Only one Ohio Power customer and no Columbus Southern Power customers participate in AEP's price curtailable service rider (PCS Rider).

"Although participation in its programs is low and the economic incentives relatively unattractive, the Companies have not hesitated to readily interrupt customers," Integrys Energy Services pointed out.

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Proposed RPM Changes Include Adjustment to Peak-Hour Period Availability

PJM's comprehensive filing to implement changes to the Reliability Pricing Model includes revisions to the peak-hour period availability provisions that are favorable to generators, such as Pepco Energy Services, with infrequently run units, PJM told FERC in an update on the stakeholder process to address treatment of such units (EL08-58, Matters, 7/3/08).

Under current RPM rules, for units running less than 50 hours during peak times, PJM uses a unit's Equivalent Demand Forced Outage Rate ($EFOR_D$) to determine availability penalties. For units running more than 50 hours at peak times, PJM uses a unit's peak-hour Equivalent Forced Outage Rate ($EFOR_P$).

Pepco Energy Services had filed a complaint at FERC over the use of $EFOR_D$, contending that using $EFOR_D$ is an inaccurate and biased measure for peak-hour-period availability charges, because a resource that is available during the approximately 500 peak hours can nonetheless be assessed a substantial penalty if it is unavailable during the approximately 8,260 hours that fall outside of the peak-hour periods in a delivery year (Matters, 4/23/08).

FERC held the complaint in abeyance pending a stakeholder process.

During the stakeholder process, tariff language was developed to allow generation resources that operate less than 50 service hours to use the lower of $EFOR_D$ (based on full Delivery Year) or $EFOR_P$ (based on peak hours) in determining the peak-hour period availability penalties. At the request of RPM Buyers and the PJM Load Group, a capacity owner would have to maintain its election of using either the $EFOR_P$ or $EFOR_D$ metric for at least four years.

The change was packaged into three alternate proposals for comprehensive reform of RPM. None of the three alternatives received a required supermajority for action by the Members Committee.

PJM chose to file its non-consensus proposal for RPM reforms in the absence of a supermajority recommendation, to facilitate settlement discussions (Matters, 12/15/08). In that filing, PJM proposed to revise section 10(f) of Attachment DD, at First Revised Sheet No. 623, to provide that the peak-hour period availability measure of an infrequently run resource "shall be the lower of the resource's $EFOR_D$ (based on Delivery Year outage data) and its $EFOR_P$."

FERC Accepts Southern Co. Cost-Based Rate Ceiling

FERC conditionally approved Southern Company's proposed cost-based rate tariff, providing for "up to" cost-based rates applicable to short-term (less than one year) wholesale sales of electric energy and capacity, effective January 1, 2009 (ER09-92).

Under the cost-based rate, Southern will use a ceiling of: (1) a capacity (demand) charge component calculated using FERC's stacking methodology to determine the units most likely to participate; (2) an energy charge component based on the anticipated variable cost; and (3) any transmission charge pursuant to an Open Access Transmission Tariff (or verified charge by an entity not subject to the Commission's jurisdiction) agreed to be borne by the seller.

The capacity charge is based on the weighted cost of the Southern generating units that are deemed likely to participate in the service. The energy charge is equal to the anticipated out-of-pocket variable cost of energy that would not have otherwise been incurred, plus a 10% adder for difficult to quantify costs. The transmission component reflects a pass-through of transmission service charges directly incurred by Southern Companies in connection with a given transaction.

Shell Energy North America had argued that Southern did not provide enough information as to how the proposed tariff functions, or its potential impact on wholesale markets within the Southern Balancing Area Authority. Although Southern asserted that the tariff filing is separate and distinct from its market-based rate authority, the proposal may still have market power mitigation implications, Shell had noted. Shell also sought to link the tariff with Southern's proposed auction for available capacity (Matters, 12/19/08).

FERC found Shell's concerns to be outside the scope of the cost-based tariff proceeding. FERC agreed the tariff is "separate and distinct" from Southern's market-based rate authority.

The Commission required Southern to provide further explanation regarding its method for determining which variable cost calculation will apply for a given transaction, and the method for determining which resources are expected to support a transaction under the alternative variable cost calculation.

Briefly:

N.Y. PSC Seeks Comments on Reserve Margin

The New York PSC is accepting comments on whether it should adopt the Installed Reserve Margin established by the New York State Reliability Council, which was set at 16.5% for the 2009-10 capability year (Matters, 12/25/08). Comments are due Jan. 13 (07-E-0088).

NYISO ... *from 1*

"Market participants rely on the NYISO's markets being accurate and reflective of the NYISO's FERC-approved tariff provisions," TOs noted.

But in this case, the NYISO allowed market participants to conduct transactions both within and outside the NYISO marketplace based on incorrect assumptions, even after the error had been discovered.

"It is essential that the NYISO immediately inform market participants when it discovers a modeling error that has an impact on the NYISO markets, and of the nature of its corrective action," TOs told FERC. Information concerning modeling errors and the subsequent corrections should be made available to market participants, and not treated as either confidential or of no relevance to market participants, TOs said.

"The granting of a waiver under the current circumstances would signal to the NYISO that it is acceptable for it to wait an entire year before notifying parties of the problem and that it is acceptable to avoid full and complete review of identified tariff violations," TOs cautioned.

"A waiver at this time also would signal that it is acceptable for loads (through uplift) to continually pay for NYISO errors," TOs added.

While the NYISO filing contains some information regarding the impact of the system modeling error on market participants, that information is not sufficient for individual market participants to assess how the error may have affected them, TOs reported. For example, the NYISO notes that the error resulted in "relatively higher day-ahead market prices in western New York and relatively lower day-ahead market prices in eastern New York."

However, the NYISO did not provide market participants with the estimates of day-ahead prices at various locations in New York that were produced by those simulations. Instead, the NYISO only reported data on prices between the Central and Capital zones, and even then the data reported is limited. The NYISO should be directed to provide full price estimates to market participants so that, for example, LSEs serving load in western New York can estimate the impact that the error may have had on the cost of their day-ahead purchases, TOs urged.

The NYISO filing also describes a $7.4 million increase in uplift charges, net of increased congestion rents collected as a result of the modeling error, but the information contained in the NYISO filing regarding the cost increase is insufficient, TOs said. The NYISO has not provided detailed data comparing flows that were scheduled over the Central East Interface in the day-ahead market each day to the flows over Central East that would have resulted if injections and withdrawals of energy in the market matched the injections and withdrawals corresponding to the TCCs outstanding, TOs noted.

Instead, the NYISO merely reported the total impact of its error on congestion rents collected in the day-ahead market and the cost of buying out day-ahead schedules in real time. The NYISO should be directed to provide full price estimates, interface flows, schedules and limits, and related information to market participants, TOs argued.

In addition, the NYISO should be directed to provide market participants with a daily breakdown of the $7.4 million impact. The NYISO has asserted that as time went on, virtual traders responded to the difference between day-ahead and real-time prices by scheduling additional transactions, which "tend[ed] to increase [day-ahead] congestion to levels that better reflected the real-time congestion." Consequently, it appears that most of the $7.4 million impact occurred before virtual traders had a chance to change their bidding strategies, TOs pointed out.

AEP Ohio ... *from 1*

For example, in 2007, the AEP Ohio utilities issued curtailments to the seven customers taking service under Schedule IRP-D, totaling 246 hours for each of the seven customers. "This is significant considering that PJM has not curtailed any customers in AEP's zone since AEP joined PJM in 2004," Integrys Energy Services observed.

"But what provides a significant insight into the Companies' state of mind and that should be noted by the Commission as it considers this issue is that the Companies can curtail under Schedule IRP-D and then proceed to make an off-system sale of the curtailed energy for the benefit of its shareholders (not customers)," Integrys Energy Services charged. While the PJM tariff currently imposes a cap on off-system sales, AEP is pursuing raising that limit in a PJM working group, the Integrys marketer reported.

Integrys Energy Services noted the General Assembly has not granted PUCO authority over utility customers, and thus PUCO cannot implement the proposed ban on PJM demand response participation, while Constellation NewEnergy argued the proposed ban would clearly violate state energy policy as established in Section 4928.02, Revised Code. Both suppliers also raised federal jurisdiction arguments as well.

AEP Ohio has not presented any calculations or data comparing its own load response programs to those offered by PJM, Integrys Energy Services noted. The Integrys marketer reported that Ohio customers have enrolled over 580 MW into the PJM Emergency Load Management (ILR) Program, which correlates to an average of $27.7 million injected annually into the Ohio economy by just one PJM demand response program.

AEP argued that demand response by bundled service customers amounts to a resale of electricity, and is prohibited under the Companies' tariffs and is subject to ongoing jurisdiction of PUCO.

PUCO Staff, along with marketers, consumer advocates, and industrial customers, opposed AEP's proposed nonbypassable POLR charge. Under the proposed new POLR charge, Ohio Power customers would face a 153% increase in their POLR fee while Columbus Southern customers would face a 742% increase, Constellation NewEnergy noted. Constellation expressed concern that the increased POLR charge will act as a "tax" which will deter customers from shopping.

Staff found AEP's charge to overestimate any POLR risk, and suggested that POLR risk can be eliminated by including in the ESP a provision stating that additional power to serve returning customers would be procured on the market. Under such a mechanism, returning customers would pay market prices, or the incremental costs of the purchased power would be recovered through the Fuel Adjustment Clause. The current POLR fee set in the Rate Stabilization Plan is appropriate to cover migration risk, Staff said.

Although the proposed POLR fee increases are high on a percentage basis, AEP countered that its POLR fee would still be among the lowest in the state. The suggestion that returning customers pay market prices when returning to standard service is not supported by SB 221, AEP said, and PUCO lacks authority to force customers to pay such market rates. AEP pointed to the separate provision in SB 221 for a Market Rate Offer as showing the ESP cannot reflect market prices, since otherwise an MRO would not be necessary.

AEP's proposed deferral of incremental Fuel Adjustment Clause (FAC) expenses was opposed by Staff, consumer advocates, and marketers. Under the ESP, AEP would limit FAC increases to 15% per year, with costs recovered over seven years from 2012 to 2018 via a nonbypassable surcharge.

While statute permits deferrals to promote rate stability, the Ohio Consumers Counsel noted the $461 million in carrying costs from the deferral will not act to stabilize prices. "This, by itself, constitutes a significant and unnecessary increase in rates to customers," OCC said.

Constellation NewEnergy agreed, noting, "Since AEP Ohio is not discounting the cost of generation, only delaying its collection with carrying cost, the deferral has the effect of increasing the total cost of generation by adding in a substantial amount of interest which all customers have to pay." Staff noted PUCO rejected proposed deferrals in FirstEnergy's ESP.

The FAC will reflect projected costs of the Companies' compliance with the renewable energy mandates, including solar energy requirements, set out in Ohio Rev. Code §4928.64. All costs of such alternative energy portfolio standards are to be bypassable, but the proposed deferral of FAC costs would be nonbypassable. Thus, Staff recommended that any PUCO order direct AEP to recover any deferred alternative energy portfolio standards costs through a bypassable rider.

Staff supported AEP's proposal to purchase incremental power on a "slice of the system basis," but argued the amounts bought should be lower. AEP proposed making purchases equal to 5% of each Company's load in 2009, 10% in 2010, and 15% of load in 2011. However, Staff believes the purchases should be limited to cover the load AEP acquired in agreeing to serve Ormet as well as from its purchase of Monongahela Power. Those additional responsibilities only amount to about 7.5% of the Companies' load, and thus Staff recommended that the purchased power authorization be that amount on average, in increments of 5%, 7.5%, and 10% during the ESP.