Energy Choice Matters

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Spark Energy to Pay $100,000 in Mass. Settlement

Spark Energy is to pay nearly $100,000 to resolve allegations that it violated Massachusetts consumer protection law, although it did not admit to any wrongdoing as part of an agreement and Assurance of Discontinuance with the state's attorney general.

"True competition for retail electric supply service in the Commonwealth cannot take place when consumers are given misleading or confusing information about their options for competitive supply services," Attorney General Martha Coakley said.

The AG had alleged that Spark telemarketing agents misrepresented Spark in way that confused customers into believing Spark was NSTAR; failed to clearly disclose a monthly service charge that consumers had to pay; and did not properly describe potential savings from switching as required by law.

Spark is to refund $44,000 in monthly charges to about 900 customers and waive early termination fees for any customer seeking to opt out of their current contract.

Another $55,000 will be paid to the AG's Local Consumer Aid Fund and will be used to bankroll regional consumer assistance programs to educate consumers on choosing a competitive supplier and to provide information on energy efficiency and low income assistance programs.

FirstEnergy Blasts P3 Request to Exclude Duquesne Generation from May RPM Auction

Since, "there is no legal basis for excluding Duquesne zone resources from the May 2008 RPM auction," a request from the PJM Power Providers Group (P3) is, "nothing more than an attempt to drive up prices in the May 2008 RPM auction by excluding unnecessarily from that auction available generation located in the Duquesne zone of PJM," FirstEnergy Service Company alleged in an answer at FERC (ER08-194).

Although FERC in its withdrawal order directed PJM to remove Duquesne's load from the May 2008 auction, PJM has included Duquesne zone generation on the 2011-12 RPM Resource List, "because an official withdrawal date for Duquesne has not yet been approved by FERC, and as such the transmission and other requirements that would be required of external resources do not yet apply to the Duquesne zone generators."

In response, P3 filed an emergency request for ruling, asking FERC to treat Duquesne resources as external to PJM and urging that those resources must satisfy ATC requirements for deliverability to participate in RPM.

Removing load in the Duquesne zone from the May auction, while leaving the capacity in the Duquesne zone, "creates a critical mismatch between loads and resources that will distort market outcomes and undermine reliability for the 2011-12 Delivery Year," P3 claimed.

But excluding the 3,000 MW of readily available generation in the Duquesne zone, which would likely drive up RPM prices and potentially degrade reliability, "is the real market distortion about which the Commission should be concerned," FirstEnergy replied.

"[I]t is not possible for FirstEnergy and owners of those generating resources to comply with the requirements applicable to external resources for an obvious reason: they are *not* external resources," FirstEnergy reminded.

Since FERC only conditionally granted Duquesne's exit from PJM, and Duquesne has yet to

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Bangor Hydro Warns Maine PUC on Long-Term Contracts

A London Economics report (Matters, 2/29/2008) prepared for the Maine PUC, "should be supplemented to thoroughly analyze the costs and benefits arising out of reallocation of risk to T&D utilities and their customers that will arise out of long-term contracts for energy and capacity," Bangor Hydro-Electric argued (2008-104).

The report, BHE noted, lacked analysis demonstrating how long-term contracts could provide real net savings for customers.

"Instead, the Report concludes without analysis that long-term contracts with new generators benefitting from transmission expansion 'could' mitigate cost increases for electricity consumers," BHE pointed out.

Noting that even London Economics admitted to the "hypothetical" nature of the benefits, BHE urged a net benefits analysis to allow consumers to be fully informed of the risks inherent in long-term contracts.

"It is clear that long-term contracts, by their very nature, re-allocate risks between the energy suppliers and T&D utilities (and their customers)," BHE reminded.

BHE considers the report incomplete since it lacks an in-depth analysis of those risks. The utility is concerned that in a PUC notice seeking comments on the report, the Commission indicated that it, "plans to proceed with a long-term contract solicitation after the resource adequacy report and plan is finalized."

Without a study of the net benefits of contracts, BHE fears long-term contracts, "will have consequences unforeseen by the Commission."

Sempra Gives Real-Life Example of Needed CONE

FERC, "should not be misled by an analysis that utterly ignores the current market and the <u>actual</u> prices being offered in favor of an opinion based solely on economic theory and speculation," Sempra Generation argued in a reply over setting a new Cost of New Entry for the May 2008 RPM auction (ER08-516).

The IPP was responding to an analysis performed for RPM Buyers, a group including state regulators and consumer advocates, which had argued that a higher CONE is not needed (Matters, 3/7/2008).

Sempra told FERC of its real-life example of trying to develop a merchant project in PJM -- its fully-permitted Catoctin Power facility in Frederick County, Md.

Sempra explained that for Catoctin, "a year's worth of revenue at the current CONE versus the proposed CONE amounts to more than $20 million in foregone revenue."

"That amount is significant enough that, even over the life of the project, Sempra Generation would be unlikely to move forward with the Catoctin project on a merchant basis at the current value for CONE," Sempra told FERC.

"The premise underlying the CONE value is that it reflects a developer's costs for bringing new generation to the market, and Sempra Generation believes that the current value does not reflect those costs, whereas the proposed update by PJM is much more likely to allow new generation to enter," added Sempra.

Sempra cautioned that its concrete example demonstrates that if CONE data is not updated as PJM has requested, "the entire construct of the RPM could be undermined."

IPP: Fees for Declined Dispatches Could Harm CAISO Liquidity

A California ISO proposal to charge power traders who fail to deliver on bids to import or export real-time energy that the CAISO has dispatched could, "significantly decrease liquidity in the CAISO's real-time market," Mirant told FERC (ER08-628).

The ISO proposed an amendment to its tariff and Market Redesign and Technology Upgrade that will establish settlement charges that will be assessed to Scheduling Coordinators (SCs) who fail to deliver on bids for imports and for exports that have been accepted in the CAISO's real-time markets for energy.

The CAISO dispatch system permits SCs to indicate that they will not deliver (or "decline") dispatches for import/export energy, recognizing that there could be legitimate reasons to decline (such as a power marketer not being able to consummate a transaction as expected.)

Typically, a single decline does not pose operational problems, but simultaneous declines, especially of large MWh quantities, can result in operational problems and market inefficiencies.

Under the CAISO's proposal, an SC will be assessed charges only if its declines during a month exceed both of two thresholds – 300 MWh and 10% of the total quantity of its accepted pre-dispatched bids.

Mirant says the problem is that while the ISO is using a straight percentage to impose the fees, marketers do not know the magnitude of their declines until the month is over, and by that time it is too late to change their behavior.

"Under the CAISO's proposal, power marketers are going to face significant risk in participating in the CAISO's real-time import/ export market and if these entities decide that the risk is unacceptable, then the CAISO will lose liquidity in that market," Mirant cautioned.

In particular, Mirant expects the charges to prompt "many" small SCs to exit the market.

The percent approach is also misleading in gauging the potential magnitude of the problem, Mirant noted.

For example, an SC may have been pre-dispatched 50 MWh of imports, but declined 25 MWh resulting in a 50% decline rate.

On its face the 50% decline rate appears "egregious," but in reality, under most conditions, that decline volume would have no impact on operations or market efficiencies, Mirant explained.

The CAISO attempted to address Mirant's concern by adding a 300 MWh exemption threshold, but Mirant thinks that threshold is too low for most power marketers to continue to participate in the CAISO's real-time energy import/export market.

Boosting the threshold to 500 MWh would ease Mirant's concerns and should not cause disruption to the CAISO's operations or market efficiencies, the IPP said.

But Powerex does not think the ISO has justified allowing pre-dispatched bids to be declined.

The, "practice of declining pre-dispatched bids in the CAISO's real-time market is contrary to the binding nature of bids in other CAISO markets," Powerex said.

"For instance, as part of its Real-Time Dispatch, the CAISO issues binding instructions for resources to start-up or shut-down based on their Energy Bids, as well as their start-up and minimum load costs. Once bids are accepted in the CAISO's MRTU Day-Ahead Market, they are 'binding commitments.' Since the nature of the CAISO's real-time market is to serve as a balancing market, it is particularly problematic to allow import and export bids in that market alone to be non-binding," Powerex explained.

Powerex wants the ISO to lower the exemption thresholds to provide greater incentives for market participants to physically deliver the import and export energy they bid into the CAISO's real-time market.

The proposed 10% threshold could actually encourage SCs to submit more declines, Powerex cautioned, since 63% of SCs have monthly decline rates below 5%.

A higher decline rate threshold will encourage those bidders to converge around that higher threshold, Powerex noted, and could increase speculative behavior.

IPL Pushes for Virtual Suppliers to Bear RSG Costs

With the start of the Midwest ISO's ancillary service market delayed, the ISO should be, "directed to implement a new just and reasonable RSG [revenue sufficiency guarantee] methodology as soon as practicable," Indianapolis Power & Light (IPL) urged FERC (EL07-86 et. al.).

IPL is concerned that a MISO March 3 filing attempts to pave the way for significant delays in establishing a new RSG methodology, and provides "undue resistance" in terms of providing for refunds back to August 10, 2007 (Matters, 3/11/2008).

"The Commission should put an end to this form of 'administrative keepaway,'" IPL argued.

IPL generally supports the RSG approach detailed in March 3 filing, but thinks it should be applied from August 10, 2007, and not from a prospective future date.

The utility also wants changes to avoid an over-reliance on RSG Second Pass (i.e., uplift) payments, "in order to ensure that virtual suppliers pay their fair share of RSG costs." For example, it urged FERC to clarify or order that virtual suppliers be included in MISO's definition of "Asset Owner."

The RSG Second Pass Charge should be allocated to virtual suppliers as well as physical loads, IPL explained. But the March 3 filing states such, "allocation shall be based on Metered Load and Exports in the Real-Time Energy Market."

IPL wants FERC to clarify that virtual suppliers should bear a portion of the RSG Second Pass Charge liability, since the current draft, "does not appear to assign any of the uplift portion of RSG charges," to virtual suppliers.

Md. PSC Staff Rejects Carve-Out for Level 1 Solar RECs

The Maryland PSC staff recommended that the Commission reject a plea from the Maryland Energy Administration to make electricity suppliers purchase a set percent of their solar RPS obligations from "Level 1" sources which are those equal or less than 10 kW (Matters, 2/20/2008).

The MEA had urged that 30% of solar RECs be from Level 1 sources to spur opportunities for residential and small commercial deployment of solar systems (RM32).

But the staff noted legislation creating the solar RPS mandate (SB 595) did not carve out a specific mandate for Level 1 solar RECs.

Treating Level 1 and Level 2 (larger installations) equally in RPS qualifications provides for the, "lowest cost solar development," staff replied. It also simplifies reporting and tracking procedures.

Residential installations are typically more expensive per Watt ($8-10) than commercial installations ($5.50-6), staff research indicated. Thus, the PSC should let the solar REC market develop on its own, staff urged.

"Ensuring that this new and aggressive renewable energy program operate as economically as possible should be the Commission's priority, not the imposition of [an] additional requirement that will likely increase costs," staff argued.

Solar REC offers should only be required to be posted on a website for five business days before REC generators can offer their RECs to out-of-state parties, the staff affirmed.

Baltimore Gas & Electric had argued five days is too short a period and suggested a 15-day posting.

But the staff anticipates that, "solar RECs will be commoditized to the point that decisions to buy them will not require more than five business days."

Staff favors imposing as few limitations as possible on a market as nascent as the solar REC market, and REC developers had successfully shown the shorter posting period is desirable, staff noted.

Briefly:

N.Y. PSC Rejects Rehearing Requests in Long-Term Planning Docket

The New York PSC rejected requests for rehearing of its December Order, Initiating Electricity Reliability and Infrastructure Planning (07–E-1507), from utilities which had argued the Commission's order incorrectly excluded utility-built projects from consideration for potential long-term contracts needed for reliability. The Commission asserted its December Order did not, "establish the parameters for balancing competing proposed projects; render specific decisions on particular projects; or create formal presumptions." Since the Order stated it was not the Commission's, "intention at this time to reach any conclusions in this proceeding regarding the need for new supply-side or demand-side infrastructure or other programs," the Order did not address the need for mandatory contracts to provide capacity.

FERC OKs PJM Market Monitoring Pact

FERC accepted an uncontested settlement which will allow PJM's market monitor to operate independently of PJM management (EL07-56 et. al). The pact, reached in

December, provides that Monitoring Analytics, formed by current market monitor Joseph Bowring, will serve as an external market monitor for an initial term six years and will be able to fully participate in the stakeholder process. The settlement also increases state commissions' access to confidential market information through a certification agreement that ensures the state commission will protect the information. FERC also denied rehearing requests from the Organization of PJM States and a coalition led by the District of Columbia Office of Peoples Counsel. FERC affirmed that PJM did not violate its tariff and also explained a paper hearing for the case was sufficient and reasonable.

Epic Urges Long-Term Solution to MISO FTR Credit Policy

The Midwest ISO's proposed changes to boost credit requirements for Financial Transmission Rights (FTR) bidders are adequate as a short-term remedy but could unnecessarily harm the market and impede trading in the long-run, Epic Merchant Energy told FERC (ER08-622). MISO started a review of its credit policies after defaults in PJM's FTR market, and suggested higher collateral requirements as an immediate action that could be implemented before the 2008 annual auction. Epic wants FERC to affirm that the new policies are meant only as an interim measure, as MISO intended, and that they do not harm the markets' liquidity in the long-term. The new policies aren't path-specific requirements which would more accurately reflect risk, Epic noted, and may over-collateralize some transactions while under-collateralizing others. Stakeholder talks to find a better long-term solution are ongoing, Epic told FERC, and the proposed changes for the 2008 auction should be replaced as soon as practical.

FERC Rejects Complaint on NYISO Price Corrections

FERC rejected a complaint against the New York ISO from Black Oak Energy regarding price corrections at the NYISO-PJM interface and the NYISO-ISO New England interface during several instances in 2005 (EL07-95). FERC found that the filed rate doctrine gives the ISO the authority to correct erroneous real-time prices that its load forecasting software produced on October 30, 2005, and concluded that the ISO's use of day-ahead prices as a proxy was reasonable. A software malfunction associated with the switchover from daylight saving time had caused the error, and Black Oak had argued the ISO was obligated to follow temporary emergency procedures (TEP) contained Attachment E to set proxy prices. But FERC concluded the ISO was not restricted to correct prices under the limited authority of the TEP.

PUCT Staff Net Metering Proposal Set for Wed. Vote

The PUCT staff affirmed its view that net metering for distributed renewable generation should separately track energy use and energy sales, in staff's proposal for publication (34890). REPs had argued such separate tracking was essential given the nature of the ERCOT market (Matters, 3/14/2008), but some renewable groups had pushed for simpler meters which could run backwards and allow customers to "bank" electricity. The staff found such proposals would be inconsistent with legislation for distributed renewable generation. The proposal for publication also clarifies that TDUs will report metered values to ERCOT, a clarification sought by Reliant Energy.

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satisfy all of those conditions, generators in the Duquesne zone remain within the metered boundaries of PJM, FirstEnergy explained.

Generation owners in the zone cannot receive firm transmission service on the Midwest ISO's OASIS for transmission in the Duquesne zone since PJM is still administering Duquesne's transmission facilities.

"The P3 Group thus asks the Commission to impose a condition on the participation of generators in the Duquesne zone in the May 2008 RPM auction that the generators *cannot* satisfy," FirstEnergy noted.

Section 3.2 of the PJM Transmission Owners Agreement requires Duquesne to put in place arrangements for transmission service for existing transmission customers that is comparable to service currently provided by PJM, FirstEnergy noted. The mandate requires any existing network service reservations in PJM be converted to firm point-to-point reservations in the Midwest ISO.

Thus, existing transmission arrangements allowing for the deliverability of generation in the Duquesne zone to loads elsewhere in PJM will remain unaffected, as a functional matter, by Duquesne's presumed departure from PJM, FirstEnergy asserted.

P3's argument that Duquesne zone resources should be excluded from RPM because there is no guarantee they would be deliverable in 2011-12 is, "simply wrong," FirstEnergy said.