Energy Choice Matters

July 1, 2008

Madigan Wrong on Edison Mission High-Offer Strategy Allegations

Illinois Attorney General Lisa Madigan's "new evidence" that purportedly showed Edison Mission Energy was still using a high offer strategy in PJM despite assurances to the contrary turns out to be flat-out wrong, the AG was forced to admit in a filing at FERC yesterday (IN08-3).

It turns out the plants that submitted bids to sell energy at $999/MWh in the PJM wholesale market from March 2003 through October 2007 were not owned by Edison Mission as Madigan's complaint had suggested, the PJM Market Monitor told the AG (Matters, 6/19/08).

In fact, the identified units are external to PJM and were not capacity resources in PJM for the period from January 1, 2003 through the RPM auction for 2007/2008 with one exception. One of the identified units was a capacity resource in 2005 for one month, comprising 0.33% of all the unit offer days for the identified units.

Nevertheless, the AG insisted that FERC still investigate Edison Mission because, "all of Midwest Generation's units sell electricity at prices that track the real time market, rather than the day ahead market," which the AG believes is inconsistent with the result expected from PJM's requirement that capacity resources must offer all available energy into the day-ahead market. During the first half of 2008, Midwest Generation sold 2,603 MW as capacity resources through the RPM Auction, the AG said.

Brattle Recommends RPM Refinements, Endorses Basic Design

Although the Reliability Pricing Model has an "impressive record" of attracting new resources and retaining existing resources while significantly improving reliability within Locational Deliverability Areas (LDAs), The Brattle Group recommended a series of changes to improve the capacity market design, in a study commissioned by PJM.

Brattle recommends maintaining RPM's basic design elements, including the sloped Variable Resource Requirement (VRR) curve, the three-year forward time frame, and the one-year commitment period.

PJM is to hold a stakeholder forum on July 31 to discuss the report's recommendations, and an ongoing stakeholder process is expected to emerge from that meeting.

Brattle does not specifically address whether market mitigation processes are effective since that point has been addressed by PJM's Market Monitoring Unit. Brattle also does not address the desirability of forward capacity markets in comparison to fundamentally different market designs, such as energy-only markets.

Cost of New Entry (CONE)

The recent 2011-12 auction was informative, Brattle noted, because the gross CONE value that was used, net of energy and ancillary service (E&AS) margins, to anchor the VRR curve was substantially below the gross CONE level that PJM believes is required to be consistent with the cost of constructing new generating capacity.

Despite this gross CONE level, the auction cleared with a surplus of capacity at prices significantly below the Net CONE value at which the VRR Curve was anchored. Over 2,300 MW of new generation resources, over 400 MW of new demand resources, and over 3,000 MW of imports

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NYISO to Issue Re-bills to Correct ESCO Overcharges

FERC granted National Grid's petition to direct the New York ISO to re-bill the months of March 2005 through August 2005 because a National Grid software error caused ESCOs to be overcharged by nearly $7 million (Matters, 3/14/08, 2/25/08).

The error, introduced late in the billing process to correct an unrelated error, caused National Grid bundled SC-3 customers to be under-billed by $3.9 million, and NYPA to be under-billed $2.9 million (EL08-40).

NYISO had refused to correct the bills absent a FERC or court order because they were discovered after the tariff-provided period for corrections had expired.

But FERC found that in the specific circumstances at hand, it is appropriate to order NYISO to adjust the invoices for the period March through August 2005 to fix the errors. "To refrain from doing so would yield an unjust and unreasonable result, requiring some customers to pay too much for energy purchases over the relevant periods, while others would pay too little due to erroneous billing data."

While market participants were untimely in making the request to correct the billing, FERC noted that such untimely action was not due to failure on their part to act once the errors were discovered, but rather due to the unusual nature and timing of the errors, which were introduced late in the billing process and impacted amounts that were not originally in question.

NYISO will have six months to issue corrected invoices.

DPUC Draft Would Allow Long-Term EDC Contracts for RECs

The Connecticut DPUC would allow electric distribution companies to enter into long-term contracts for Class I RECs from new resources for a portion of their RPS obligations under a draft decision (07-06-61).

Per legislative language, any RECs obtained pursuant to long-term contracts would be used to meet EDCs' standard service and supplier of last resort RPS requirements. All costs associated with the long-term REC contracts would be recovered through the generation service charge.

Contracts could be for no more than 50% of new RECs needed to meet RPS and shall not include energy or capacity.

While the draft "strongly supports" a competitive RFP procurement of contracts, it would not preclude negotiated contracts, provided the EDCs submit sufficient documentation that meets a high burden of proof of favorable market conditions and ratepayer benefits. Long-term contracts would have to be approved by the DPUC.

EDCs would not be required to enter into long-term REC contracts, since a mandate could compel the EDCs to enter into ill-timed contracts that could disrupt the market or lead to stranded costs.

The draft finds that authorizing EDCs to enter into long-term contracts for new Class I RECs would expand REC availability and lead to lower prices for renewable energy. Long-term EDC contracts would convey greater market certainty, and hence lower market risk to renewable investors, the draft reasons. That would lead to a lower required return for investors, lower financing costs to the renewable generators, and lower renewable energy prices offered in the market. Lower market risk for renewable generators would create a more favorable investment climate, and is likely to increase the total supply of renewable generation, the draft determined.

Short-term REC contracts offered by competitive suppliers do not convey the same confidence in long-term demand that could lower financing costs for renewable generating facilities, the draft finds. Long-term EDC contracts would provide a constant revenue stream for renewable generators so their RECs would likely be offered at a lower price than RECs obtained by short-term contracts.

Long-term EDC contracts would have a favorable effect on diversifying the electricity resource portfolio away from fossil fuels, the draft adds, providing a hedge.

New resources would be defined as Class I facilities not having begun operation as of the date of the REC contract procurement.

The DPUC does not expect a need for Class I RECs to be procured via long-term contract until 2010, when supplies are expected to be tighter.

The draft would not allow the use of long-term contracts for procurement of Class II and Class III RECs at this time since the supplies of those RECs are expected to be sufficient to meet RPS obligations.

The draft would reject Connecticut Light and Power's proposed compensation mechanism for contract administration functions as "excessive." The draft would authorize an incentive of 0.4 mills/kWh for projects with a capacity factor of 25% or less, 0.3 mills/kWh for projects with a capacity factor between 26% and 50%, 0.2 mills/kWh for projects with a capacity factor of 51% to 75% and 0.1 mills/kWh for projects with a capacity factor above 75%. The Department would issue the one-time payment after two years of full operation of the contract to assure customers of performance and to facilitate better estimates of future operations.

Generators Want APSouth Scarcity Pricing Region Effective This Summer

Several generators ("PJM Suppliers") urged FERC to add a new Scarcity Pricing Region known as APSouth to PJM effective this summer (ER08-1170).

PJM has filed to add the region via a section 205 filing which, due to timeline requirements, would not allow the region to be in effect this summer.

The suppliers argued that adding the Scarcity Pricing Region via a section 205 filing is not necessary, and in fact counter to, a settlement regarding scarcity issues. The settlement contemplates that new Scarcity Pricing Regions will be established annually when the settlement criteria are satisfied, suppliers reported.

Commission intervention to implement the APSouth region this summer is especially warranted, suppliers claimed, because the APSouth Scarcity Pricing Region is essentially the same geographic region covered by the Scarcity Pricing Region that it replaces.

"This is not a situation where a new portion of PJM will be covered by scarcity pricing for the first time," suppliers observed.

In the future, Scarcity Pricing Regions should be implemented via an information filing, or a section 205 filing submitted far enough in advance for changes take effect for the summer, generators contended.

Suppliers also told FERC that PJM is delaying taking comprehensive action on scarcity pricing because it is awaiting the Commission's issuance of an order in the Wholesale Market Reform NOPR, and urged FERC to direct RTOs to promptly implement market rules incorporating scarcity pricing.

Briefly:

Blu Power Dropping Customers to POLRs

Prepaid REP Blu Power, which only recently became active in the Texas market (Matters, 4/21/08), has asked ERCOT to move its 2,000 residential customers to POLRs, citing volatility in the wholesale market and the cost to serve the customers. Blu Power acquired 1,200 customers from W Power & Light during the spring, as W Power & Light stopped accepting new customers. Blu Power intended to hedge its supply, but could not before congestion-related price spikes hit in May, and since then has not been able to find reasonable long-term wholesale prices. Blu Power had been charging about 18¢/kWh for its prepaid plan and had organic growth of about 800 customers. Blu Power said it will return money to customers who have account balances and is searching for investors to stay in the market. Blu Power is led by Michael Anderson, founder of USI Energy, the utility billing and energy management firm which was bought by Ista in 2005.

Integrys Proposes Disclosure Label for Conn. Suppliers

Integrys Energy Services has created and filed a proposed product disclosure label to be used by Connecticut competitive electric suppliers in Docket 07-05-33. After it became apparent at a May technical conference that changes were needed to the DPUC's originally proposed label, the Department extended the date by which suppliers must comply with its labeling order from May 30 to August 30, 2008. Integrys's proposed label is based off the utility labels produced by Connecticut Light & Power and United Illuminating, adjusted for competitive offers, and reflects limited feedback from other suppliers.

ALJ Refuses to Consolidate CenterPoint Meter Dockets

A PUCT ALJ rejected Staff's request to

consolidate CenterPoint Energy's advanced meter information network (AMIN) docket (35620) and CenterPoint's advanced metering system deployment docket (35639). The judge noted consolidation would effectively moot the purpose of considering an interim solution for smart metering, such as AMIN, ahead of wider deployment by delaying the AMIN case (Matters, 6/23/08).

Advantage IQ Acquires Cadence

Avista's energy consulting arm Advantage IQ has acquired Cadence Network, and announced it is seeking to monetize the company in two-to-four years. The potential monetization of Advantage IQ could be completed through an initial public offering or sale of the business depending on future market conditions, growth of the business and other factors. The combined client list tops 500 and includes more than 70 Fortune 500 clients. The combined firm will keep the Advantage IQ name and will remain a subsidiary of Avista with headquarters in Spokane, Wash. Existing offices in Cincinnati, Denver and Atlanta are to be maintained. Advantage IQ CEO Stu Stiles will continue in that role while Cadence Network CEO Jeff Hart will become COO of Advantage IQ.

Liberty Surpasses 30,000 Customers

Liberty Power grew revenues to $193.4 million in 2007, an increase of over 60%, it disclosed to Hispanic Business. Customer count has topped 30,000, and enrollment has been about 5,000 customers per quarter during the year, according to publicly reported data.

FERC Approves "Seller Credit" in PJM

FERC accepted PJM's latest credit policy changes and established "Seller Credit," which is Unsecured Credit extended to participants that have a consistent long-term history of selling in PJM (ER08-569). The Seller Credit is designed to give participants the credit benefit associated with the value of their established long-term history of net sales, while mitigating the risk presented to other PJM Members from such Unsecured Credit. Along with other safeguards, the Seller Credit is limited to participants that have maintained monthly net positive sales positions in the PJM markets over the most recent continuous 12 month period. FERC dismissed the concerns of AEP, finding that AEP failed to show that a participant's Net Sell Position is not a reasonable indicator of a participant's ability to meet its credit obligations. Commissioner Jon Wellinghoff agreed with AEP and dissented, cautioning that under the proposal a large net seller position in the energy market could be used to support transactions in the Financial Transmission Rights markets.

Rendell's PUC Picks Confirmed

As expected, the Pennsylvania senate confirmed Wayne Gardner and Robert Powelson to the PUC (Matters, 6/20/08). Legislators, however, could not work out differences in legislation over electricity rate caps and the matter will be held until after the summer recess.

DPUC Opens Docket to Review Energy Plan

The DPUC opened docket 08-06-20 to review the Connecticut Energy Advisory Board's comprehensive plan for the procurement of energy resources under Public Act 07-242.

Oncor One-Time Credit to Get Rolling

A PUCT ALJ dismissed docket 34040, Staff's petition for a review of Oncor's rates, at the request of Staff and other parties. With dismissal, the timeline for distribution of Oncor's one-time $72 million credit through REPs can begin (Matters, 6/30/08).

BluePoint Signs Demand Response Contracts

BluePoint Energy (Chapeau) has executed demand response aggregation agreements with 24 commercial, institutional and industrial customers in California and Hawaii totaling 22 MW.

FERC OKs Strategic California Settlement

FERC approved a settlement among Strategic Energy and the California Parties stemming from the Western electricity crisis in which Strategic will pay $1,625,025 from its Power Exchange unpaid receivables to the California Parties, which includes the state's three IOUs, attorney general, PUC, and Department of Water Resources. The Commission also approved a $1.1 million settlement among the Pinnacle West companies and the California Parties.

Brattle RPM ... *from 1*

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(including capacity from the former Duquesne zone) cleared in the auction despite the much lower capacity prices, Brattle noted. Only approximately 500 MW of new generation and close to 300 MW of demand resources did not clear at the relatively low auction clearing price.

Brattle noted the results suggest that either (1) new resource owners are willing to commit at prices that are below their levelized total cost of entry during the initial year because they are confident that the RPM design will yield long-term results that compensate them for their total entry costs; (2) the administratively chosen reference technology that offers the lowest total cost of new entry (a combustion turbine) does not actually result in the lowest net cost of new entry; and/or (3) the resource owners' anticipated future energy and ancillary service margins are higher than the historical value currently used to determine Net CONE under the PJM tariff.

In fact, since energy prices have been steadily increasing over the past several years, it is unlikely that historical energy revenues will be an accurate predictor of future energy revenues, Brattle found.

The substantial amounts of cleared new capacity at comparatively low prices in the most recent auction suggests that Net CONE has not increased significantly despite higher construction costs. Brattle thus recommended that PJM further evaluate the extent to which a significant administrative upward adjustment to Net CONE is necessary despite the documented substantial increase in total construction costs.

Brattle recommended that PJM consider revising the CONE and E&AS framework to: (1) determine gross CONE for the reference technology with the lowest Net CONE value; (2) determine the E&AS offset to gross CONE based on estimated future E&AS margins for the reference technology; and (3) consider introducing an ex post true-up for actual E&AS margins earned by the reference technology during the delivery year. Ultimately, empirical, rather than administrative, adjustments would appear to be a promising approach to setting Net CONE at levels consistent with market expectations of the most economic technologies, their costs, and E&AS offsets, Brattle added.

Brattle dismissed suggestions to base empirical Net CONE adjustments on the offers of new resources rather than the auction clearing prices. Brattle cited market monitoring challenges and potential market power abuses under such a system, since offers would directly impact the demand curve. Offer data for new capacity is sometimes thin, especially in small LDAs, Brattle added, and it's unclear whether the scope of "new capacity" considered should include only combustion turbines or also other generation technologies, demand response, uprates to existing capacity, or capital investments to retain existing capacity.

Forward Timeframe and Commitment

Brattle does not share concerns that a three-year forward timeframe and one-year delivery period might be too short. The three-year forward timeframe appears long enough to allow a significant amount of resources to react to price signals to enter or delay before major irreversible financial commitments need to be made, Brattle reported. Longer-term forward commitments would likely be less effective by increasing supplier risks and ultimately customer costs.

Brattle explained that baseload resources are not built for a single delivery year three years from the date of the auction, but are built on the expectation that RPM will continue to exist and capacity payments will continue to be available if and when the resources become operational.

Concern that RPM's one-year commitment period provides insufficient price certainty to attract new generation resources is overstated, Brattle argued. At the RTO-wide level, RPM provides support for long-term investments through capacity prices that are comparably stable and predictable even without multi-year guarantees, Brattle claimed. Brattle is concerned, however, that price stability does not exist within LDAs, since LDA prices are very sensitive to changes in transmission import capabilities. In smaller LDAs, even the addition of one large power plant can substantially reduce the LDA's price premium.

To address these pricing uncertainties within import-constrained LDAs, Brattle recommended that PJM consider making a multi-year lock-in mechanism (or an auction product reflecting a multi-year commitment period) broadly available to new resources within LDAs.

Capacity Exclusions

Brattle thinks the current RPM rules inefficiently exclude Fixed Resource Requirement (FRR) capacity. FRR entities are subjected to a "sales cap" on the total capacity that they may offer into RPM markets even if they have extra generation not needed for their own reliability requirements. Brattle argued that excluding such capacity increases the capacity clearing price and may lower RTO-wide reliability.

Brattled "strongly" recommended that PJM consider eliminating the sales cap to enable such resources to participate in RPM, and that the must-offer obligation, which applies to all other PJM resources, also be applied to any FRR capacity that is not needed to satisfy FRR entities' own reliability requirements and has not been committed elsewhere.

Brattle also suggested that PJM reduce the capacity "buffer" FRR entities must hold above their forecast requirement, since it is more efficient to manage uncertainty through RPM's incremental auctions.

Penalties

Brattle favors significant changes to the RPM penalty structure.

Deficiency penalties appear to be excessive, potentially discouraging entry of new resources and creating unnecessarily high penalty risk for existing resources, Brattle contended.

New resources, in particular, already face the risk of not coming online due to queue uncertainty, permitting risks, and state regulatory obstacles, and they may be discouraged from participating given the heavy deficiency penalty rate.

Brattle reported that there is also some indication that when the contractual relationship between the owner of a non-utility generator and its marketing agent ends during the delivery year, the agent may be reluctant to offer the capacity into RPM because it risks facing deficiency charges if the contractual relationship is not extended through the end of the delivery year. Such risk is "substantial," Brattle said, since the RPM forward commitment is made three years in advance of the delivery year and the penalties applied are quite high.

To reliably encourage the procurement of capacity to replace commitment deficiencies, Brattle would reduce deficiency penalties to 1.2 times the higher of: (1) the auction resource clearing price in which the capacity was originally cleared; and (2) the third incremental auction resource clearing price.

Meanwhile, availability penalties may be insufficient to penalize certain types of resources for being unavailable during peak hours, Brattle noted. Brattle also noted some penalties are unnecessarily asymmetric across resource types. Demand resources and Interruptible Load for Reliability (ILR), in particular, face a more lenient penalty structure than generation resources, Brattle said.

In order to avoid attracting low-quality resources, availability penalties should be sufficiently large to put all revenues at risk for capacity that is not made available, Brattle argued. In particular, Brattle is concerned that the 20% penalty per load management (LM) event for non-performing demand resources does not put all of the resource's capacity revenues at stake, because there are typically only one or two load management events per year. Not only may this result in a windfall to demand response providers, Brattle cautioned, but it would also likely degrade reliability by attracting low-quality resources that cannot respond when needed.

Brattle suggested requiring demand resource suppliers to return the fraction of their revenues corresponding to the fraction of annual LM events to which they did not respond. That design would be comparable with generation availability penalties, Brattle said.

Brattle also believes that the current RPM penalty structure is unnecessarily lenient on generation with poor availability during peak hours. The 50% penalty cap on generators with poor Peak-Period Equivalent Forced Outage Rate (EFORp) works against the objectives of RPM by potentially forgiving poor performance during the very hours when reliability is most vulnerable, Brattle reasoned. To avoid rewarding poor performance, Brattle recommended that 100% of resources' capacity payments be at risk.

Locational Deliverability Areas

Brattle recommended that LDAs be defined based on transmission constraints rather than service territories.

Brattle suggested eliminating the pre-auction screen, which can artificially eliminate price premiums in the LDAs that have adequate but expensive local capacity.

In base auctions, Brattle favors incorporating planned transmission additions into the Capacity Emergency Transfer Limit (CETL) only when there is a reasonable expectation that the project can be online as anticipated. If actual CETL is later found to differ from the assumptions applied for the base auction, PJM should consider adjusting for associated LDA capacity shortfalls or surpluses through incremental auctions.

Other Recommendations

Brattle also suggested:

• Various measures that allow energy efficiency and price-responsive demand resources to be reflected in RPM on a more timely basis.

• Redesigning incremental auctions so that they are more liquid, more able to address decreases in load and changes in LDA import capabilities, and more consistent with the base auctions by: (1) creating a single type of incremental auction; (2) adding into incremental auctions the portion of the VRR curve that did not clear in the base auction, updated for changes in load forecasts; and (3) integrating ILR resources into the incremental auctions.

RPM Results

Brattle reported that since RPM was implemented:

(1) at least 4,600 MW of capacity has been retained that otherwise would have retired;

(2) almost 10,000 MW of incremental capacity has been committed; and

(3) the volume of generation interconnection requests has grown to make an additional 33,000 MW of new generation projects eligible to participate into future RPM auctions.

The most recent 2011-12 delivery year auction saw a shift in that new generation was a significant part of the auction resources, as opposed to the transitional auctions which mostly attracted demand response, reduced net exports, and cancelled or delayed retirements.

The majority of new additions have been gas-fired, but a new merchant coal plant as well as several hundred megawatts of renewable generation have also been committed. The addition of the merchant coal plant is significant, Brattle observed, because it indicates that the RPM design may also be a significant factor in supporting the entry of competitive baseload generating capacity.

The "substantial" amount of capacity represented by units that might either be retired or revenue-deficient in the absence of RPM highlights the importance of capacity prices for existing resources, Brattle concluded.

The impacts RPM has had on new and existing resources show that capacity price signals are important for facilitating the most cost-effective entry, investment, and retirement decisions, Brattle determined.

Customers have paid capacity prices that are "consistent" with reserve margins and the administratively determined marginal cost of capacity for the RTO, i.e., the Net Cost of New Entry (CONE) of approximately $170/MW-day. While the clearing price fell to $110 in the most recent auction due to the loss of Duquesne zone load, clearing prices would have been approximately $150/MW-day had the Duquesne zone generation chosen not to participate in the auction. The most recent auction saw 6,000 MW of capacity offers that did not clear in the auction, but even if Duquesne had remained with PJM, over 4,000 MW of capacity offers would not have cleared, Brattle reported.

This significant amount of uncleared capacity indicates a significant increase in competition between existing and a variety of new capacity resources compared to previous auctions in which little capacity remained uncleared, Brattle confirmed.