Energy Choice Matters

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FirstEnergy Ohio EDCs Claim PUCO Transition Charge, Fuel Rider Order to Cost $2 Million/Day

The FirstEnergy Ohio utilities petitioned PUCO for an immediate stay and rehearing of the Commission's decision to end regulatory transition charges at two of the utilities, and end a fuel rider at all three utilities, in setting rates to be charged absent a new standard service offer established pursuant to SB 221.

PUCO ruled that transition charges should end at Ohio Edison and Toledo Edison, and that the Fuel Recovery Mechanism should be eliminated at all three FirstEnergy utilities (Matters, 1/8/09).

Unless reversed, the Commission's order will result in the FirstEnergy utilities losing over $2 million of cash per day, the utilities claimed. The attendant deteriorating financial condition from such outlays may result in a downgrade of the utilities' credit ratings of to non-investment grade, leading to collateral calls on the utilities by counterparties in amounts in excess of $30 million, the utilities said.

FirstEnergy claimed PUCO incorrectly applied SB 221 in its decision, noting PUCO set rates using a provision meant to set interim rates after an Electric Security Plan had been "authorized" but withdrawn. Although PUCO approved, and FirstEnergy subsequently withdrew, FirstEnergy's ESP, the plan was never actually "authorized," FirstEnergy insisted, since tariffs reflecting PUCO's changes to the ESP were never filed. FirstEnergy argued PUCO is compelled to continue the existing 2008 rates without any adjustments, except to allow the recovery of new fuel and purchased power costs.

FirstEnergy further argued that the regulatory transition charge tariffs actually did not contain an end date, and thus should continue. The end of the charges results in a revenue reduction of over $450 million per year.

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Generators Oppose PJM "Hold-Back" Provision for Base Residual Auction

PJM's proposal to hold back 2.5% of projected demand from the Reliability Pricing Model Base Residual Auction was one of the main objections generators raised in comments on a wide-ranging filing from PJM to revise the capacity market (ER09-412).

Under PJM's proposal (Matters, 12/15/08), 2.5% of projected demand from the Base Residual Auction (BRA) would not be acquired in the BRA. Thus, only 97.5% of the region's reliability requirements would be met through the BRA, with PJM "saving" the remaining demand to be filled in future Incremental Auctions. The measure is meant to allow resources with short lead times, such as demand response, to receive capacity payments for their contribution to reliability.

PSEG and Allegheny Energy both argued the measure poses a serious threat to RPM's ability to send valid price signals for new entry, especially as PJM did not adjust the current must-offer requirement for the BRA. By failing to procure the full generation adequacy quantity required in the BRA while at the same time mandating a must offer obligation by all existing capacity resources at mitigated prices, BRA prices will be depressed. Accordingly, the need for new entry will not be properly reflected in the price and quantity results of some auctions, PSEG said.

PSEG argued the hold-back provision isn't needed to accommodate demand response, pointing to the New England Forward Capacity Market, whose experience shows that demand-side resources of all types can effectively participate in forward procurement auctions in the same manner as other types of capacity resources.

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Detroit Ed, Consumers Seek Immediate Hike in Virtual Traders' Credit Obligations

Detroit Edison and Consumers Energy opposed the Midwest ISO's intention to not include estimated resettled Revenue Sufficiency Guarantee (RSG) charges in Market Participants' Total Potential Exposure under the MISO credit policy until FERC rules on a MISO compliance filing (ER04-691-088 et. al.).

In a recent order, FERC directed MISO to refund RSG charges dating back to August 10, 2007, such that virtual traders who did not actually withdraw energy will be retroactively assessed the charges from which they had been exempt (Matters, 11/12/08). The case has been appealed to federal court.

MISO noted that including such resettlements immediately as part of a Market Participant's credit obligation may result in substantial hardship and harm to the energy market. Normally, a Market Participant would only have two business days to cure a situation where their exposure exceeds their credit limit.

MISO estimates that the aggregate amount of RSG resettlement charges that are not covered by available unsecured credit or available financial security is approximately $77.7 million.

But Detroit Edison warned that substantial harm to the market would also occur if the Market Participants that owe RSG resettlement amounts fail to cover their liabilities once invoiced, thereby causing other Market Participants to absorb those costs.

Detroit Edison argued MISO does not have the authority to defer including estimated RSG resettlement amounts in Total Potential Exposure calculations. MISO's tariff defines Total Potential Exposure as including potential exposure to non-payment associated with Real-Time Energy Market transactions, and Detroit Edison contended that the RSG resettlements are charges associated with Real-Time Energy Market transactions.

Furthermore, Total Potential Exposure includes both charges that have been settled, and also those that have been calculated, Detroit Edison said, and the RSG resettlements have been calculated. Thus they are required to be included immediately in calculating Market Participant exposure.

TXU Suggests Potential POLR Uplift Costs Should Flow to Fixed Price Customers

Any potential market uplift to be used to mitigate POLR rates or reimburse POLR providers for bad debt should be considered a change resulting from law that may be passed onto customers on fixed price and term contracts, TXU Energy suggested in reply comments on changes to the POLR process in Texas (35769).

The PUCT has asked for comments, as an alternate to its proposal for publication, on the possibility of creating an interim period where a rate less than the MCPE-based POLR rate would be charged, or ensuring POLR recovery of bad debt associated with POLR obligations. Naturally, either measure would require a source of funding (Matters, 12/23/08).

In its reply comments, TXU said, "It may be preferable to treat the entirety of the uplift of costs anticipated by this Preamble Question as a 'change resulting from federal state or local laws' that imposes new or modified fees or costs on a REP directly that are beyond the REP's control. In this way, a REP would presumably be permitted to recover these costs from fixed price and term customers in accordance with those customers' terms of service and Commission rules."

In other reply comments of note, the Texas Industrial Energy Consumers objected to the proposal put forth by the Alliance for Retail Markets and Reliant Energy that would create a $50 million POLR fund to mitigate rates and socialize bad debt through an assessment on QSEs.

Aside from opposing the fee as prejudicial (since all competitive load through their QSEs would pay the fee but large customers would not be eligible for the mitigated POLR rates), TIEC argued there is no authority that would allow ERCOT to assess the proposed emergency service fee. Under PURA § 39.151(e), the Commission can authorize ERCOT to assess a reasonable fee, "to cover the independent organization's costs." But the emergency service fee is outside the scope of this authorization, since the costs covered by the fee are not created by ERCOT, TIEC said.

The joint TDUs objected to various solutions offered by REPs and consumer groups to ensure that a pre-existing switch request from a customer is not overridden by a mass transition. Suggestions such as accelerating the requested switch date or querying ERCOT's data base of pending switches and doing manual workarounds would slow the mass transition, would be costly, and would not be effective in large transitions, TDUs said. TDUs noted that ERCOT's mass transition working group recently implemented changes regarding existing switches, and said these measures should be given an opportunity to work before additional changes are made.

ERCOT Seeks Dismissal of Wind Reactive Power Appeal

ERCOT Protocol Section 6.5.7.1 unambiguously establishes that the reactive power capability requirement for all generators required to provide voltage support service is equal to a unit's 0.95 leading and lagging power factor determined at a generating unit's maximum net power output to the grid (0.95 lead/lag requirement), ERCOT said in a motion to dismiss an appeal at the PUCT from several wind generators (36482).

The wind generators have claimed that the protocols support their position that wind resources may provide reactive power according to the capability of the units, dependent upon the output of the units at a given time (Matters, 12/15/08). Much of the wind generators' case is centered on interpreting the phrase "operating capability" as used in Protocol § 6.7.6(5).

But ERCOT countered that the appeal, "misapplies trade jargon in trying to eviscerate clear obligations under the ERCOT Protocols."

Particularly, ERCOT argued Protocol § 6.7.6(5), cited by the wind generators, addresses deployment of voltage support service by ERCOT and/or Transmission Service Providers. The section, ERCOT contended, does not establish reactive power requirements.

Nevertheless, ERCOT maintained that Section 6.7.6(5) still confirms the obligation to meet the 0.95 lead/lag requirement at all output levels. As used in the context of that section, the term "operating capability" refers to the generating unit's reactive power capability, which is defined by the 0.95 lead/lag obligation established in Section 6.5.7.1(2), ERCOT said.

"Thus, the intent of this clause is to impose the 0.95 lead/lag obligation at all energy output levels - i.e., 'at lower active output levels,'" ERCOT argued.

ERCOT also dismissed wind generators' arguments that interconnection agreements specify different levels of reactive power support, since such bilateral agreements between transmission and distribution service providers and generators do not involve ERCOT, nor do they impact the ERCOT Protocols. ERCOT also sought dismissal of the appeal on the grounds that generators failed to first seek alternative dispute resolution of their complaint as required.

Briefly:

DPUC Opens Review of Utility-Supplier Billing Rules

The Connecticut DPUC has opened a review of Conn. Agencies Regs. §16-245d-1 et. seq., relating to the billing relationship between distribution companies and competitive suppliers (09-01-07). During its investigation of Connecticut Light and Power's billing errors in early 2008 (08-02-06), it came to the DPUC's attention that CL&P does not consistently provide accurate customer data to electric suppliers in a timely manner, and therefore, electric suppliers cannot bill customers accurately or timely. Furthermore, CL&P's policy is not to provide estimated usage data for accounts in Classes 30 and higher, so electric suppliers are left with absolutely no data with which to bill customers when CL&P fails to provide actual data, the Department noted. The regulations are currently silent on such issues, and may need to be amended to set requirements for utilities to follow in their provision of customer data to electric suppliers, the DPUC said in docketing its review.

Ambit Offering New Referral Program in All Markets

Ambit Energy is offering customers in all of its active territories the opportunity to offset their energy bill by referring 15 customers to the marketer. We first reported the new referral program as part of Ambit Energy's entry into the NiMo territory in New York (Matters, 1/6/09), but

Ambit is rolling out the program in Texas and Illinois (Nicor gas) as well. Under the program, new customers have 120 days to refer 15 customers to Ambit. If they successfully do so, they will be credited with the average payment amount of their 15 referred customers, up to their total bill, either as a credit on their bill, or check (depending on billing method). In Illinois and New York, the program only applies to the supply portion of bills, in Texas, it applies to the entire bill as the ERCOT product is bundled. Customers do not receive any credit if their referrals drop below 15, and are given 60 days to replace any dropped customers.

Xcel Issues Colorado RFP

Xcel Energy announced it is seeking 2,200 MW for its Colorado distribution company between now and 2015 via an RFP, and intends to offer self-build proposals in the process. Public Service Co. of Colorado is seeking up to 700 MW of wind and solar generation through the RFP, and will consider acquiring up to 600 MW from solar thermal generation with storage capability or natural gas backup. Nearly all sources of generation greater than 30 MW may bid, except the RFP restricts coal-fired bids to those from facilities that capture and sequester at least 50% of their carbon dioxide emissions. Proposals are due April 10.

FirstEnergy ... from 1

FirstEnergy separately sought emergency approval for new Rider FUEL to recover purchased power costs for supplies through March 31, 2009 and thereafter. The surcharge, reconciled quarterly, would recover the difference between each utility's fuel costs (including purchased power, energy, capacity, planning reserve, alternative energy and credits, non-distribution uncollectible expense, Ohio Commercial Activity Tax expense and other applicable taxes, and any other expenses to provide generation service for all retail customers receiving generation service from the utilities) and the generation revenue (including generation charges and rate stabilization charges) charged to those customers.

Absent the fuel rider, the FirstEnergy utilities projected that for 2009:

- The shortfall of generation revenues to cover the cost of power purchased under the interim RFP will be $484 million, $464 million, and $273 million respectively for CEI, OE, and TE.
- Annual Net Income and Free Cash Flow from Operations are each revised downward by $315 million, $302 million and $177 million for CEI, OE, and TE, respectively. The reductions to Free Cash Flow from Operations produce negative cash generation for each of the Companies -- resulting in annual Free Cash Flow from Operations of negative $169 million, negative $270 million and negative $168 million for CEI, OE and TE, respectively.

RPM ... from 1

Allegheny added that RPM was designed to attract long-term resources, and argued resources of all types -- generating capacity, demand response, and energy efficiency --- should compete on even ground regardless of lead time.

Reliant Energy also raised discrimination arguments over the hold-back provision. The PJM proposal allows demand resources the flexibility to participate in the RPM auction in which demand resources expect the highest value for capacity to result, Reliant noted.

"In stark contrast, existing generation suppliers do not have this flexibility [and] under the PJM market power mitigation rules must offer their entire available capacity into the BRA subject to strict bid mitigation as a precondition to participation in any incremental auctions," Reliant said.

The proposal, in essence, allows PJM to act as a "price discriminating purchaser" on behalf of load by reducing demand in the BRA, then procuring potentially more resources (if available and regardless of price) to fulfill reliability requirements in the subsequent Incremental Auctions, Reliant contended.

However, the Illinois Commerce Commission argued that the amount of demand held back until the incremental auctions should be raised -- to 5-10% of demand -- to ensure an even balance of capacity and demand in the incremental auctions. The ICC argued more demand needs to be held back to produce sufficient liquidity in the incremental auctions. Otherwise, the incremental auctions will be very long on supply relative to demand, because the incremental auctions will consist of (1) newly available capacity from generator upgrades, generating unit forced outage improvements, and newly built generators; (2) capacity imports; (3) new demand response programs and new participation in existing demand response programs; (4) PJM sell-backs due to, for example, over-forecasted load levels or reductions in installed reserve margin requirements; and (5) uncleared capacity from previous capacity auctions -- all competing for just 2.5% of demand.

The result of an incremental auction that is very long on supply but short on demand is that the clearing price will be very low compared to the clearing price in the Base Residual Auction, the ICC noted.

"Such a disparity in price between the base residual auction and the incremental auctions may be destabilizing. It would be particularly destabilizing in situations in which PJM over-procured in the base residual auction and sought to sell back into the incremental auctions. In such case, retail customers would be paying too much for capacity," the Illinois Commission said.

A coalition of five Mid-Atlantic state regulators, including the Maryland PSC, suggested that the hold-back should be set at 5.7%, as did several large customers.

Also drawing the ire of most generators is PJM's provision to include an offset for scarcity pricing revenues separate from the Energy & Ancillary Services (E&AS) Offset.

Shell Energy North America called the scarcity pricing "claw-back" putting the cart before the horse, as PJM does not yet have a proposal on scarcity pricing that has cleared the stakeholder process. Yet PJM in its RPM proposal has already determined that there should be a revenue offset for any scarcity pricing mechanism, Shell noted.

Dayton Power & Light equated the scarcity revenue offset to "double dipping" and criticized it for being discriminatory to resources in PJM West, where there is virtually no congestion.

Load, however, also faulted some aspects of the scarcity offset, particularly its lag in returning revenues. On this point, PJM's market monitor agreed, telling FERC that the problem with PJM's proposal is that the scarcity offset is not matched with the appropriate recipient of capacity market revenues.

PJM's proposal is to offset scarcity revenues in the auction following the year in which the scarcity revenues were received by reducing the net Cost of New Entry in that auction. This design adjusts the market price in a Delivery Year three years after the scarcity revenues are received. Thus, there is a significant mismatch in time and a significant mismatch between those who received the scarcity revenues and those who will have their revenues reduced by the scarcity offset, the market monitor noted.

"This approach also creates uncertainty for both load and generation market participants and conveys an inaccurate price signal, especially for units that did not actually receive scarcity revenues. For example, most generating units clear in the day-ahead market and such units would generally not receive any scarcity revenues in the real-time market," the market monitor said.

The market monitor suggested that PJM should not pay scarcity rents to capacity resources in the first place, thus obviating the need for any offset. When PJM declares a scarcity event under this approach, capacity resources would not receive the full scarcity price, but would instead receive the market price less the scarcity adder.

Load groups urged FERC to adjust PJM's demand forecast and gross Cost of New Entry (CONE) adjustments given the current economic slowdown.

The ICC is concerned that the Gross CONE values reflect input costs to build a combustion turbine that were calculated at the apex of an upward commodity and materials price spiral that started to unwind in the autumn of 2008. "The ICC does not believe it would be appropriate to use a Gross CONE that is likely based upon 'bubble' pricing for use in establishing the parameters of the variable resource requirement ('VRR') curve going forward."

"In fact, all available data projecting available capacity, market prices, and consumer demand lead to the conclusion that the Base Price should be decreased, not increased. PJM's argument for an administrative increase is further flawed given the fact that it bases its conclusions on data and projections that are no longer relevant given the dramatic changes in financial and economic circumstances over the past six months," the RPM Load Group added, which is composed of several consumer advocates and large customers.

The Pennsylvania PUC, along with two muni groups, urged FERC to direct PJM to update its Base Residual Auction peak load forecast in late March, to capture current economic conditions. Under PJM's tariff, the forecast must be determined and announced by February 1.

Curtailment service providers objected to PJM's proposal to eliminate the Interruptible Load for Reliability (ILR) program. PJM proposed the elimination to encourage more demand resource to participate in the RPM auctions.

But Energy Curtailment Specialists (ECS), in comments echoed by other curtailment providers, argued that the ILR elimination would, "severely limit and possibly prohibit the maximum participation of Demand Response Resources ('DRR') in PJM's wholesale markets." As an alternative, ECS suggested that ILR should remain in the PJM market construct, but with ILR resources only paid 85% of the BRA clearing price.

"This would entice those potential customers who feel that demand response is good for their business model to transition from ILR to participation in the BRAs and/or IAs [incremental auctions], while protecting those who choose not to incur the increased risks associated with a long-term forward commitment."

ECS also told FERC that PJM needs to ease its credit requirements for curtailment providers, similar to ISO New England and the New York ISO, to reduce barriers to entry.

AEP reiterated its opposition to allowing customers who receive generation service from an LSE based all or in part on historical cost-of-service to participate in demand response outside of tariffed programs offered by utilities.

According to AEP, "[a]n inequity occurs because PJM currently allows tariff customers served by FRR [Fixed Revenue Requirement] entities to declare themselves eligible for capacity payments in the RPM market. This creates a situation where RPM LSEs pay for this interruptible capacity directly to the FRR retail customer (not to the FRR supplying entity). However, since the FRR entity is not allowed to deduct this capacity from its FRR capacity obligation, it will have to supply capacity to meet this customer's load despite the fact that the customer now has declared that it has additional interruptible capabilities. The end result is that the combined PJM footprint will procure more resources than are needed."

Consolidated Edison Energy reiterated comments made during the stakeholder process regarding the higher costs to load resulting from PJM's proposal to pay energy efficiency participating in RPM four years of capacity payments (Matters, 12/4/08).