Energy Choice Matters
November 28, 2008

FERC Accepts TPS Test for PJM Regulation Market

FERC conditionally accepted PJM's proposal to apply the three-pivotal-supplier (TPS) market power screen to the regulation market, effective December 1 (ER09-13, Matters, 10/2/08). Use of the TPS test is subject to the outcome of the Commission's ongoing investigation of the justness and reasonableness of the test in PJM's energy and capacity markets in docket EL08-47.

Under the plan as approved by FERC, PJM will replace the current mitigation of cost-based regulation offers from the two dominant companies (Dominion and AEP) at all times with a real-time mitigation approach that:

(i) Encompasses use of the TPS test as the screen for market power;

(ii) Defines available supply for purposes of the market structure screen as all offers submitted at a total price (offer plus opportunity cost) less than or equal to 150% of the cost-based clearing price;

(iii) Provides for an adder of $12.00 to the calculation of mitigated cost-based offers;

(iv) Eliminates the current practice of netting regulation market revenues against balancing operating reserve payments; and

(v) Redefines opportunity costs to measure those against the cost-based offer for the unit, rather than against the market-based offer.

The current $100/MWh price cap will remain. The $12 adder, opportunity cost revisions, and elimination of netting of regulation revenues against balancing operating reserve payments are meant to address concerns that sellers are offering less than half of their regulation capability in the market,

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TXU Suggests Study of Demand Ratchets With Eye Toward Removal for Customers Under 50 kW

TXU Energy urged that Oncor be directed to study billing all customers below 50 kW on a kWh consumption basis only, without a demand ratchet, in comments on Oncor's rate case (35717).

Demand ratchets, which are not well-understood by small customers, inhibit the creation of competitive rate plans and are the source of many customer complaints, TXU argued.

Currently, commercial customers below 10 kW are billed on a kWh consumption basis, and Oncor has proposed extending the threshold to 20 kW as part of its rate case, along with an exemption from demand ratchets for municipally-owned loads. While both changes are good first steps towards improving the customer experience, more is needed, TXU said.

TXU recommended that Oncor be ordered to conduct a study prior to its next rate proceeding to determine the impacts of moving to a waiver of the demand ratchet for all customers 50 kW and below, and to study a change in the rate design to bill commercial customers at some level above 10 kW on a kWh consumption basis rather than a demand basis.

Such changes would reduce customer confusion and aid REPs in the development of competitive rate plans that are easier to operationalize and explain, TXU said, based on customer feedback about demand ratchets and demand billing.

TXU also urged Oncor to clarify its proposed Inadvertent Gain discretionary charge. The current mechanism for REPs to return inadvertently gained customers to the original REP is through a move-in transaction. The REP at fault is responsible for the payment of the move-in fee, TXU noted. Oncor should clarify that its proposed inadvertent gain charge replaces the move-in fee to make it clear to all parties that the REP will not be charged both the inadvertent gain charge and the move-in charge, TXU urged.

UI Reports October Shopping Data

United Illuminating Switching Statistics As of October 31, 2008

Total Accounts with Alternate Supplier: 34,278

Customer Count Breakdown:

3rd Party Supplier	Residential	C&I	Total	September 30, 2008 Total
Clearview Electric	0	0	0	0
Consolidated Edison Solutions	929	734	1,663	1,727
Constellation NewEnergy	285	2,943	3,228	3,186
Direct Energy Business (Strategic)	10	656	666	663
Direct Energy Services	3,056	1,020	4,076	3,386
Dominion Retail	16,074	1,029	17,103	17,203
Gexa Energy	0	45	45	41
Glacial Energy of New England	29	370	399	406
Hess Corporation	0	58	58	56
Integrys Energy Services	9	1,613	1,622	892
Liberty Power Delaware	0	23	23	23
MXenergy	1,401	1,173	2,574	2,820
Public Power & Utility	1,521	314	1,835	1,701
Sempra Energy Solutions	29	442	471	463
Suez Energy Resources NA	0	49	49	37
TransCanada	8	458	466	465
Totals	23,351	10,927	34,278	33,069

CTCleanEnergyOptions	Residential	C&I	Total
CTCleanEnergy - Community Energy 50%	230	6	236
CTCleanEnergy - Community Energy 100%	773	62	835*
CTCleanEnergy - Sterling Planet 50%	263	2	265
CTCleanEnergy - Sterling Planet 100%	2,252	42	2,294*
Total All CTCleanEnergyOptions Suppliers	3,518	112	3,630

UI Last Resort Service (LRS)		% of Class Shopping
Total # All LRS Accts	246	
Total All LRS MWhs	114,914	
Total 3rd Party LRS Accts	218	89%
Total 3rd Party LRS MWhs	105,582	92%
UI C&I Standard Service		
Total # All C&I SS Accts	37,967	
Total All C&I SS MWhs	188,380	
Total 3rd Party C&I SS Accts	10,709	28%
Total 3rd Party C&I SS MWhs	110,624	59%
UI Residential Standard Service		
Total # All SS Res. Accts	289,222	
Total All SS Res. MWhs	150,910	
Total 3rd Party SS Res. Accts	23,351	8%
Total 3rd Party SS Res. MWhs	14,404	10%
Total All UI		
Total # ALL Accts	327,435	
Total ALL MWhs	454,204	

* Reflects data as reported by UI. Based on previous months' figures, Community Energy 100% and Sterling Planet 100% data may have been transposed during reporting this month.

DPUC Draft Would Reject UI Proposal to Place More Charges in Bypassable FMCC

A draft Connecticut DPUC decision would deny United Illuminating's application to recover Generation Services Charge-related nonhardship uncollectible expenses, DPUC regulatory commission expenses and working capital in the bypassable Federally Mandated Congestion Charge (FMCC), as part of the semi-annual reconciliation of GSCs in Docket No. 08-08-01.

UI had applied to recover such costs in the bypassable FMCC in addition to the retail access and load settlement costs that are recovered in the current one mill adder.

UI has removed such costs from its current distribution rate request in Docket No. 08-07-04.

The DPUC draft would deny the request as it is currently reviewing additional costs that may be recovered through the bypassable FMCC in Docket No. 97-01-15RE02, and is reviewing UI's distribution costs in Docket No. 08-07-04.

In its ultimate decision in Docket No. 08-07-04, the Department may determine that some costs can be removed from UI's distribution rate and transferred to the bypassable FMCC, the draft says.

FERC Approves Revised Operating Reserves Compensation, Cost Allocation

FERC accepted revisions to PJM's Operating Agreement and OATT which create "segmented" make-whole payments for Operating Reserves and also:

- Limits under certain conditions the operating parameters that may be submitted for a unit, to reduce the possibility that market power may be exerted; and
- Changes how the costs of Balancing Operating Reserves are allocated to PJM Members (ER08-1569).

FERC found the proposed revisions to the current operating reserve mechanism to be just and reasonable since they will maximize market efficiencies (Matters, 9/26/08).

The changes are meant to further solidify incentives for market participants to bid their Day-ahead quantities as close as possible to what they expect in the Balancing Market, thereby maintaining a high level of convergence between Day-ahead and Real-time Prices and maximizing market efficiency. The modifications are also meant to strengthen the incentive for generators to follow PJM dispatch instructions, and prevent the exertion of market power by generators committed to provide Operating Reserves through the submission of inflexible operating parameters.

Among the changes is the development of "segmented" make-whole payments available for Operating Reserves sellers when the total offered price exceeds the total energy market value of the pool-scheduled resource. Segmenting the make-whole payments is intended to motivate Market Sellers to follow PJM dispatch, and to encourage the resource to continue operating when its minimum run time has expired, and when it has already fulfilled its output commitment to produce energy for the Day-ahead Energy Market.

Specifically, for resources committed in the Day-ahead Energy Market, the proposal would segment the Operating Day into multiple segments based on (a) the number of hours that the Market Seller committed to produce energy in the Day-ahead Energy Market or the resource's minimum run time, whichever is greater, and (b) for each synchronized start of the resource, the number of hours that the resource was operated at PJM's direction in the Real-time Energy Market beyond the longer of its Day-ahead schedules or minimum run time in the same calendar day.

Segmenting is meant to combat the destruction of a resource's previously earned LMP margin in cases where the LMP during hours of PJM-directed extended operation is below the resource's offer. Under current procedures, some LMP margin is lost during such circumstances because the current Operating Reserve make-whole payment is calculated based on the unit's operation for the entire 24-hour calendar day. By segmenting the make-whole payment and providing separate make-whole compensation specifically for the hours of extended operation, the owner of the resource can retain any margin earned in the earlier hours and be made whole separately for the extended period of operation, PJM explained.

Detroit Edison Submits Settlement on Choice Incentive Mechanism Reconciliation

Detroit Edison, Michigan PSC Staff, Constellation NewEnergy and the Michigan Attorney General have entered into a settlement regarding reconciliation of Detroit Edison's Choice Incentive Mechanism (CIM) for 2007, and the allocation of additional revenue from decreased choice sales to reduce unrecovered regulatory asset balances (U-14838).

The Choice Incentive Mechanism is a tracking mechanism that determines the change in total non-fuel revenue associated with increases or decreases in annual Electric Choice sales from a total base Electric Choice sales level of 3,400 GWh, with a 200 GWh deadband.

The actual annual Electric Choice sales at Detroit Edison in 2007 were 2,239 GWh, which is below the base level of Electric Choice sales (3,200 GWh net of the 200 GWh deadband adjustment). The resulting additional non-fuel revenue received, less an $8 million deadband adjustment, was $40 million.

Under the settlement, the $40 million will be used to reduce unrecovered regulatory asset balances related to the Regulatory Asset Recovery Surcharge (RARS) mechanism.

The initial allocation resulted in RARS balances of zero for <15 kW and >=15kW C&I customers, with excess funds in those classes re-allocated to the Residential and SMC classes.

Large Customers Push for More Testing of MISO ASM to Review Mitigation Measures

Large customers in the Midwest ISO urged FERC to direct MISO to conduct additional operational ancillary service market trials to test and demonstrate that the Independent Market Monitor (IMM) has systems and procedures in place to both detect and mitigate market power that is exercised by the physical withholding of ramp capability (ER09-24).

To address artificial scarcity witnessed during market testing, MISO has proposed tariff changes to provide incentives for generators to offer and maintain ramping capability (Matters, 10/24/08). The Coalition of Midwest Transmission Customers has opposed the incentives, recommending instead additional mitigation measures.

The customer coalition seized upon MISO's "astounding" statement that the IMM did not actively participate in such operational tests, which were designed to test the ability of the systems to successfully price, dispatch and control resources.

"In that test context, it was unnecessary for the IMM to monitor and report on the test results upon or soon after their occurrence," MISO said. MISO did brief the IMM about the test results, and the IMM discussed with the Midwest ISO the scarcity pricing issues and potential solutions.

Since the IMM supports MISO's ramping proposal, "there is no need for additional measures to improve the IMM's monitoring of ramp withholding just because the IMM did not actively participate in the operational tests," MISO stated.

But in an answer, the Coalition of Midwest Transmission Customers argued that until such time as MISO is able to demonstrate, based on actual tests, that the IMM is fully capable of detecting and remedying the physical withholding of ramp capability, the effective date of MISO's ancillary services tariff should be suspended.

FERC Grants Temporary Waiver for LIPA Financial Assurance Treatment in ISO-NE

FERC granted ISO New England a temporary waiver that allows the ISO to continue treating the Long Island Power Authority as a Municipal Market Participant for purposes of financial assurances.

ISO New England determined in October that LIPA, which had been treated as a Municipal Market Participant since 2001, did not qualify for such categorization under the current Financial Assurance Policy, since LIPA is organized under New York law, and not under the laws of a state of New England.

FERC granted the temporary waiver because the waiver will remedy concrete problems in a way that merely continues the status quo, without causing any harm, or risk of harm, to third parties. The Commission also concluded ISO-NE and LIPA acted in good faith.

Since its registration in 2001, LIPA has fully complied with the creditworthiness requirements for Municipal Market Participants, has maintained an investment grade rating, and timely paid all invoices.

When ISO-NE reached its conclusion regarding LIPA's lack of eligibility as a Municipal Market Participant, LIPA became subject to the credit requirements applicable to all Non-Municipal Market Participants. Accordingly, LIPA complied with ISO-NE's request for additional financial assurance by depositing $5.3 million in cash collateral into the ISO-NE settlement account and granting ISO-NE a security interest for such amounts. The amounts will be refunded with the granting of the temporary waiver.

TPS Test ... *from 1*

and that offer-capped sellers offer even less.

PJM estimates that parties controlling units with regulation capability offered only 30-40% of that capability into the market in 2007. Offer-capped sellers offered even less - only 15-30% of their capability

FERC found that raising the adder to the calculation of mitigated cost-based offers from the current $7.50 to $12 is just and reasonable, which was the only seriously contested facet of PJM's proposal.

The Commission noted the current $7.50 adder applies only to the Mid-Atlantic Area and to the two companies subject to mitigation (AEP and Dominion). Under the revised tariff provisions, mitigation will now potentially apply to all suppliers in PJM that fail the TPS test, FERC observed. The $12 adder is designed to create an incentive for more firms to participate in the regulation market, because, although PJM is receiving sufficient bids for regulation service, it is not receiving the range of participation that it would expect in a competitive market, FERC reasoned.