Energy Choice Matters
June 19, 2008

Dominion East Ohio Exit from Merchant Function to Enter Second Phase in 2009

PUCO approved the second phase of Dominion East Ohio's (DEO) plan to exit the merchant function and permitted the LDC to implement a Standard Choice Offer (SCO) for eligible customers starting April 1, 2009, per a stipulation agreement (07-1224-GA-EXM).

Phase 2 is designed to build choice-eligible but non-shopping customers' relationship with a distinct supplier to bridge DEO's eventual exit from the merchant function.

DEO will conduct an SCO auction to set a monthly variable price for non-shopping customers eligible for choice. About 3/4 of DEO's remaining commodity customers are eligible for choice.

About 1/4 of DEO commodity customers are either not eligible to participate in the energy choice program due to arrearages or payment history, or are percentage of income payment plan (PIPP) customers. A standard service offer (SSO) auction, which is currently used to serve all non-shopping customers, will still be used to serve those customers during phase 2.

In the SCO auction, suppliers will compete for the right to serve the load of nine tranches which are comprised of randomly assigned groups of customers and are designed to yield similar weather-normalized annual volumes in the aggregate. Each tranche will be comprised of approximately 3.8 Bcf of annualized load for 30,000 residential and 2,600 non-residential customers. Bidders, who must be certified competitive retail natural gas providers, may bid on multiple tranches up to a three-tranche limit. A supplier can be awarded bids in both the SSO auction and the SCO auction.

The SCO auction will begin under a descending clock format, using the results of the SSO wholesale supply auction as the floor price. If the SCO auction concludes at a price above the SSO

... Continued Page 5

AG Madigan Alleges Edison Mission Continuing High Offer Strategy

Illinois Attorney General Lisa Madigan alleged Edison Mission is still engaging in its "High Offer Strategy" that prompted a FERC investigation despite Edison Mission's assurances it discontinued the practice in April 2006, Madigan told FERC in a rehearing request (IN08-3).

Madigan cited "new evidence" in the form of an analysis by Robert McCullough which alleges Edison Mission has continued to withhold capacity resources from the PJM Day Ahead market through at least the first quarter of 2008.

Edison Mission recently agreed to pay a civil penalty of $7 million resulting from a series of misleading representations made during FERC's investigation, though the stipulation did not make a finding as to whether improper bidding occurred (Matters, 5/20/08).

Analyzing Edison Mission EQRs, McCullough claimed, "Edison Mission's transactions with PJM take place at, or very close to, PJM's Real Time prices." McCullough claimed that nearly all of Edison Mission's Midwest Generation units have sold energy to PJM at prices that match the ComEd Real Time prices very closely. Those prices do not match the "appropriate" Day Ahead prices, McCullough claimed.

"Given the size of Midwest Generation's involvement in the RPM market, a large proportion of the units in Illinois should be selling energy at Day Ahead prices," McCullough asserted.

McCullough alleged that data from Midwest Generation's Form 10-Ks and EQRs indicate that Edison Mission receives capacity payments while continuing to avoid selling energy into the Day

... Continued Page 6

RESA Says Congestion True-Ups Preventing Apples-to-Apples Shopping in Connecticut

The Connecticut DPUC should re-open its default service docket (06-01-08) to examine whether the use of "Scenario B" bids by utilities should be discontinued, the Retail Energy Supply Association urged (08-05-14).

Under Scenario B bids, wholesale power suppliers pass through their actual congestion costs to utilities as they are incurred, which requires utilities to develop an estimate of such costs at the beginning of each rate period. But that can lead to estimates that are substantially different from actual costs, as was the case at Connecticut Light and Power last year, when it over-collected congestion costs by nearly $27 million, with over $21 million of the overcollection attributable to smaller Standard Service customers. Large true-ups are needed to reconcile the costs.

"This estimation and adjustment approach impedes the ability of consumers to compare the true price of CL&P's generation service with the prices of competitive offerings, obscures market price signals that encourage energy conservation, and undermines the efforts of retail electricity suppliers to compete with CL&P's rates and sustain a reliable customer base in Connecticut," RESA argued.

While the Last Resort Service over-recovery of $5 million for 2007 was returned to LRS customers during the first two quarters of 2008, only $0.6 million of the Standard Service over-recovery was credited to the six-month Standard Service rates effective January 1, 2008 -- leaving $21 million to be credited to rates effective July 1.

The estimation and true-up approach prevents an apples-to-apples comparison by customers, RESA noted, as true all-in generation prices for default service aren't available since congestion costs may be trued-up. Competitive retailers, however, offer all-in prices that are fixed and final for a given contract period.

The true-ups can cause default service prices to deviate from market prices in an irrational pattern, RESA pointed out, such as CL&P's July 1 generation rates which will actually decrease due to the true-up even though the underlying supply costs are more expensive. Thus, customers' price signal to conserve energy and implement efficiency measures due to higher market prices is blunted, and the lower Standard Service rates erroneously indicate to customers that efficiency is needed less even though supply costs have risen.

While the Department permitted the use of Scenario B contracts to avoid congestion cost premiums in supply contracts, RESA noted that the Bethel to Norwalk 345 kV transmission project is now fully operational, which, according to CL&P, has caused congestion costs to fall by nearly $150 million during its first year of operation. It is reasonable to assume, RESA suggests, that the risk premiums embodied in the "all-in" fixed price wholesale supply contracts (which CL&P calls "Scenario A" contracts) have also abated, making the justification for Scenario B contracts less compelling.

Even if risk premiums remain, RESA argued that the over-recoveries associated with Scenario B contracts amount to ratepayer loans to CL&P which do not pay any interest. The DPUC must weigh the risk premium savings against customers' lost interest income, RESA contended.

RESA also noted that United Illuminating does not use Scenario B contracts, which calls into question the need for such contracts.

Energy Michigan Not Convinced New Line Losses Reflected in Bundled Rates

Energy Michigan questioned whether Consumers Energy, as directed by the Michigan PSC, has implemented the same new line losses for its bundled customers as it has done for retail access customers (U-15245, Matters, 6/11/08).

Nowhere in a June 13 filing or in the Case in Chief presented by Consumers is there any proof that similar new line loss increases were incorporated in retail full service Primary tariffs, Energy Michigan reported.

"Nor, upon examination by at least one expert associated with Energy Michigan, is there any evidence of the substantial increase in retail full service Primary rates which would have occurred upon implementation of similar line loss increases for retail full service customers," Energy Michigan added, in requesting that Consumers present workpapers showing the increases.

Assuming that a competitive retailer delivers power at transmission voltage to a Consumers Energy point of delivery, and that the point of delivery is a Consumers transformer or the power travels through Consumers' lines at transmission voltage until it reaches the Consumers transformer, Energy Michigan asked how can there be real power losses of 2.407% (the new loss factor) on the high side of that transformer? In other words, Energy Michigan questioned how a competitive supplier delivering current at transmission voltage would incur real power losses of 2.4% before the current even passed through any Consumers transformer, when such a delivery path previously had been assessed zero losses.

Energy Michigan argued that the losses must be explained because they impose, "a severe handicap on [retail access] providers which does not appear to have been imposed on Consumers Energy as a retail full service provider."

TXU Offers iThermostat for Remote HVAC Control

TXU Energy yesterday launched its iThermostat product, a thermostat that allows customers to control their home's heating and cooling system from any Internet-connected device, and allows TXU Energy to cycle a customer's heating and air conditioning system during periods of peak energy demand.

The iThermostat is initially being offered to customers in the Oncor area, though TXU plans to later expand its reach. Customers must have a broadband connection and reside in a single-family home to be eligible for the product.

An iThermostat is free to customers who participate in the TXU Energy Conservation Program, which permits TXU to cycle HVAC load during peak times, typically between 1 p.m. and 7 p.m. from May through September. Customers can override any cycling.

The conservation program can be added onto to any TXU pricing plan, and has a two-year term. A $150 exit fee applies to the conservation program, but customers can switch among TXU pricing products during that time while remaining on the conservation program, subject to the individual terms of those pricing plans.

The iThermostat uses broadband Internet service and ZigBee technology and was developed in partnership with Comverge and Digi International.

Delaware PSC Raises Retail Margin for Hourly Priced Customers

Delmarva Power can keep charging its previously accepted interim reasonable allowance for retail margin (RARM) on fixed-price SOS customers for the rest of the rate-year even though Delaware PSC staff calculated that it over-collects costs to be recovered from such customers (07-364). Since the difference for an average residential customer is only 32¢ annually, the Commission ordered Delmarva to true-up the overcollection next year and to keep using the current RARM.

But for hourly-price customers, the PSC did order a change to increase the RARM from what was approved on an interim basis. The Commission also directed that recovering the undercollection occurring since the interim rates were approved for the Feb. 29 billing cycle be spread over the remaining months of the year.

The changes stem from staff interpreting the Docket No. 04-391 settlement agreement regarding the allocation of the $2.75 million component of the RARM between fixed-price and hourly-price customers differently from Delmarva. Staff believes that the settlement provides that a $175,000 per year allowance for hourly-priced service billing software costs should be added to a $90,000 contribution from hourly-priced customers (which is the hourly-priced portion of the $2.75 million component). Delmarva's RARM calculation, however, reflects the $175,000 allowance as comprising the entire contribution by hourly-priced customers. Thus staff recommended, and the Commission accepted, increasing the proposed RARM for hourly-priced service by $90,000 and decreasing the proposed RARM for fixed-price service by $90,000.

Staff calculated the RARM for fixed-price customers to be $0.002414/kWh compared to Delmarva's proposed RARM of $0.002441/kWh, or $0.000027 per kWh less. For a residential customer using 1,000 kWh/month, the adjustment would only amount to $0.32 per year. Thus the Commission approved the interim rates unchanged, but ordered a true-up in next year's RARM.

For the GS-P hourly-price customers, staff calculated the RARM to be $0.03039 per kW above the Delmarva proposal for customers with demand below a peak load of 600 kW, and to be $240.62 per month greater for customers above 600 kW peak load capacity.

The Commission ordered that the RARM for hourly-priced customers be raised, effective 60 days from its order, to reflect staff's calculations. The RARM costs undercollected from hourly-priced customers due to the lower interim rate in effect since the Feb. 29 billing cycle are to be spread among the remaining billing months in the compliance year, the PSC ordered.

The PSC also gave final approval to Delmarva's new SOS rates which went into effect June 1 and had been given interim approval in May.

The Commission accepted on an interim basis, subject to further investigation, Delmarva's proposed Transmission Service Charge for both SOS classes. The transmission charge is being raised from $1.139/kW-month to $1.395/kW-month, effective July 1.

N.Y. PSC Approves $172 Million Annually in Fast-Track EEPS Programs

The New York PSC adopted utility targets through 2011 for its Energy Efficiency Portfolio Standard and approved $172 million in annual funding for fast-track programs (07-M-0548).

The question of utility incentives, however, remains open, as do the issues of on-bill financing and roles of demand response and distributed generation.

NYSERDA received $85 million annually to fund five fast-track programs while $87 million annually is to go to utility-administered programs once they are approved. The funds will come from an increase to the System Benefits Charge.

The PSC claimed the EEPS program when fully funded is expected to provide more than $4 billion in benefits to customers through 2015.

N.Y. PSC Accepts Reforms to National Grid Low-Income Plan

The New York PSC approved National Grid's plan to modify its low-income affordability program and provide additional arrears forgiveness credits to help more low-income customers (01-M-0075).

The program changes include requiring the utility to provide a monthly, instead of annual, arrears forgiveness credit, eliminating excessive deferrals to participants' arrears balances, and limiting participation in the program to 24 months.

The revisions are meant to address the high attrition rate of Grid's program and ensure that the arrears of participants decrease as intended.

Grid expects the average number of participants will increase 11% from 5,464 to 6,075, and that the total annual arrears forgiveness amounts will increase 83% from $789,000 to $1.45 million under the modifications. In the first quarter of the year, nearly 260,000 residential customers owed arrears totaling $188.1 million in the utility's service territory, as compared to slightly more than 250,000 residential customers owing $151.2 million in the same period a year ago.

To be eligible for the program, a customer must be approved for the federal Home Energy Assistance Program. The customer must be in arrears, have a history of broken payment arrangements and have a monthly negative cash flow, or have a referral from a local human service agency and/or be unable to afford necessary medication, proper nutrition, or some other life necessity.

Customers receiving only electric service are responsible to pay for 95% of their average monthly bill. Customers receiving electric and gas service are responsible to pay for 92.5% of their average monthly bill. The remaining incremental bill amounts, representing 5% and 7.5% reductions, respectively, reflect savings from energy use management education. These amounts, along with any other customer under- or overpayment amounts, are deferred to the customers' arrears.

Briefly:

PUCT Staff Wants to Consolidate Two CenterPoint Smart Metering Cases

The PUCT staff moved to consolidate

CenterPoint Energy's advanced meter information network (AMIN) docket and CenterPoint's advanced meter deployment plan docket (35639) since they involve common questions of law and fact; the AMIN docket is simply an accelerated deployment of the meters (Matters, 6/10/08). Staff added that the outcome of the AMIN docket could potentially affect the more comprehensive deployment docket as the AMIN docket could pre-determine specific policy determinations.

Wal-Mart Again Urges DPU to Let Customers Keep Capacity Revenues from Efficiency Measures

Wal-Mart opposed a settlement regarding National Grid's energy efficiency programs in Massachusetts because the pact would force customers to cede Forward Capacity Market (and transition payment) revenues to Grid to fund other efficiency measures as a condition of receiving utility sponsored rebates, rather than those payments being retained by customers (08-8). Wal-Mart argued such a condition limits the value of efficiency programs to customers, but the DPU rejected a similar argument in approving Western Massachusetts Electric's efficiency programs (Matters, 3/11/08). Wal-Mart also claimed Grid has failed to meet DPU directives to report capacity bid into FCM as a result of efficiency programs, and urged the DPU to investigate the matter to ensure the capacity market proceeds are funneled back into efficiency programs available to the class of customers responsible for the proceeds.

Three New REPs in ERCOT Market

The PUCT approved REP certificates for Credit Suisse Energy (#10164), Lehman Power Services (#10163) and Bounce Energy (#10162) (Matters, 5/15/08).

Mitchell Energy Management Services Wants Md. Broker License But Has Already Contracted With Customers

Mitchell Energy Management Services, which recently obtained a broker license in Delaware (Matters, 5/12/08), applied for a broker and aggregation license in Maryland, but disclosed that it has contracted with Maryland customers without a license because it was unaware Maryland required brokers to be licensed. Mitchell Energy Management applied for broker/aggregation authority for C&Is in the four IOUs plus Choptank and SMECO. President David Mitchell was previously Director of Business Development, Mid-Atlantic, for Constellation NewEnergy and also had a stint at Delmarva Power.

Hopf On The Move

Joe Hopf is leaving his post as president of PPL EnergyPlus to become president of PSEG Energy Resources & Trade. Hopf previously worked at Goldman Sachs and AmerenEnergy and replaces Kevin Quinn, who will become vice president of corporate planning for PSEG. PPL named Robert Gabbard as Hopf's replacement as president of PPL EnergyPlus. Gabbard recently joined PPL's marketer as senior vice president of trading after stints at Conectiv and CMS Energy.

DEO SCO Auction ... *from 1*

wholesale auction result, the SCO auction will terminate in accordance with pre-established end-of-auction rules. However, if the going price in the SCO retail auction falls to the SSO wholesale auction price and the market remains over-subscribed, the SCO auction will transition into an ascending auction format. In the ascending auction format, suppliers will bid for the right to serve tranches of customers at the price established in the SSO wholesale supply auction. DEO expects that the bidding in the SCO auction will reflect the incremental value of, and that the winning bidders will receive the benefit of, serving specific customers to whom they can market other offers and services.

SCO customers will receive their commodity from a specific supplier who won the customer in the SCO auction. DEO will purchase the supply from the SCO supplier for resale to the customer, and the supplier will be identified on the customer's bill.

DEO will assign on-system storage rights to the suppliers awarded tranches in both the SSO and the SCO auctions.

The SCO will begin April 1, 2009 with an initial term of one year, with the first auction occurring before Feb. 15, 2009. The SSO auction for PIPP and ineligible choice customers will also occur before Feb. 15.

To bridge the gap until SCO begins, a seven-month SSO auction for all non-shopping customers will be conducted for the period of Sept 1, 2008 through March 31, 2009, effectively extending phase 1 of DEO's plan.

In February 2010, DEO will conduct another retail SCO auction to secure supplies for the one-year term from April 1, 2010, to March 31, 2011. After that term DEO expects to completely exit the merchant function, but that move will require additional PUCO approval.

Edison Mission ... *from 1*

Ahead market so that it can sell into the Real Time market.

McCullough also cited PJM data which does not disclose bidders and does not distinguish between Day-Ahead and Real-Time bids. McCullough concluded that one bidder with bids the same general size as those of Midwest Generation as reported in FERC's investigation, and with a "comparable" number of units to Midwest Generation, submitted approximately half of all megawatt-hours using bids above $900/MWh through October 2007 (the most recent data). "The available evidence indicates that the Midwest Generation High Offer Strategy has continued after April 2006 and continues to through the most recent EQR first quarter 2008," McCullough alleged.

FERC should consider suspending or revoking Edison Mission's market-based rate authority, Madigan urged.

Madigan also requested the Commission order Edison Mission to preserve any and all documents and data relating to the allegations set forth in the pleading, since during FERC's investigation Edison Mission deleted e-mails which it had been instructed to keep.

Separately, the National Rural Electric Cooperative Association raised the concern that the Edison Mission settlement may have closed the Commission's doors to any attempt by affected market participants to demonstrate that Edison Mission's bidding practices violated PJM's then-applicable tariff and Edison Mission's then-applicable market rate schedule, and may improperly immunize Edison Mission from re-settlement of PJM markets so as to honor tariffed rules, disgorgement of unjust enrichment, or any other remedy that would reverse the consequences to market participants should improper behavior be proven.