Energy Choice Matters

November 20, 2008

MXenergy Electric Customer Growth Masked by Hedging Losses

MXenergy's net loss for the quarter ending September 30 widened to $64.5 million from $18.2 million a year ago on higher unrealized hedging losses of $78.6 million.

The loss on an adjusted EBITDA basis, which excludes certain hedging and other impacts, was $10.3 million, compared with an adjusted EBITDA loss of $9.2 million a year ago. Gross natural gas profit fell $4.7 million year-over-year, mainly on lower-of-cost-or-market storage valuation, partially mitigated by a $1.9 million increase in electricity gross profit. Gas gross profit would have increased by $2.5 million year-over-year absent the storage valuation.

Higher electric gross profit was driven by a 108% year-over-year increase in average residential customer equivalents (RCEs), leading to significantly higher sales volumes. "Significant" organic customer growth in Texas, Massachusetts, Connecticut and New York -- largely due to targeted direct sales marketing activities and a wider range of products offered to customers -- was credited for the electric customer growth. One RCE represents a natural gas customer with a consumption of 100 MMBtus per year, or an electricity customer with a consumption of 10 MWhr per year.

Electric RCEs at quarter's end grew 44,000 to 99,000, while gas RCEs grew 20,000 to 576,000 year-over-year.

Average annualized in-contract customer attrition was approximately 30% for the quarter, which compares to a three-year average attrition rate of 22%. Higher attrition during the quarter stemmed from a steep drop in competitive market prices in certain markets, most notably Texas, which resulted in an unusually high rate of fixed rate customers who decided to terminate their contracts in favor of lower rates offered by competitors, MXenergy said. However, MXenergy also added a significant number of new customers in Texas who decided to migrate to MXenergy from competitors whose

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MISO Would Charge Only 25% of CONE for Repeat Capacity Deficiency in Peak Months

The Midwest ISO would charge LSEs with deficient capacity under the Module E resource adequacy program 100% of Cost of New Entry (CONE) for the first month of any deficiency, but would reduce the penalty to 25% of CONE, or less, in subsequent violations, it proposed in a compliance filing.

In an October order on MISO's resource adequacy program, FERC agreed with stakeholders that had argued MISO's original proposal to assess the full CONE value of $80,000/MW-month for every month an LSE is deficient was excessive. FERC noted such a penalty could encourage LSEs to over-procure capacity (Matters, 10/21/08).

Under MISO's new proposal, LSEs will only be charged 100% of CONE for the first monthly violation. If the LSE is deficient again by an amount less than or equal to the maximum of any previous monthly deficiency during a Planning Year, the financial settlement charge will be 25% of the CONE value if the deficiency occurs in July, August, December, January and February. For any subsequent deficiency during any other month, the LSE will be assessed a financial settlement charge of 8.3% of the CONE value.

If an LSE has an increase in its deficient MW amount greater than any previous maximum monthly amount for the planning year, the incremental amount above the previous maximum monthly deficient MW amount would be assessed 100% of Annual CONE, as it would be the first occurrence at the new

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Calif. Marketers Urge Use of TRECs for 2008 Compliance Year

A proposed decision that would allow the use of tradable RECs (TRECs) for California RPS compliance should be clarified to permit immediate use of TRECs, including use in the 2008 compliance year, the Alliance for Retail Energy Markets and Western Power Trading Forum said in comments on the draft (R. 06-02-012).

The proposed decision is inconsistent on when TRECs may be used -- at one point suggesting TRECs may be used immediately upon approval of the decision, while at another point suggesting REC trading may not commence earlier than January 1, 2009 (Matters, 10/30/08).

AReM and WPTF see no reason to defer authorization of the use of TRECs to the 2009 compliance year, assuming the decision is ultimately approved by the end of 2008.

AReM and WPTF further argued that the proposed $50 transitional price cap could distort markets, and is ill-suited to cover a wide range of renewable technologies producing RECs.

Marketers expressed concern about the draft's provision that all RPS-obligated LSEs will be required to file reports on TREC purchases, sales, and prices with PUC Staff so Staff can monitor the market. AReM and WPTF urged clarification on whether such reporting is in addition to the semi-annual RPS compliance reports. If so, marketers argued that new reporting requirements would burden LSEs, particularly smaller non-utility LSEs.

AReM and WPTF "strongly" objected to the TREC price reporting requirement for all LSEs, arguing non-utility LSEs have never reported RPS price data before, and that they have their prices disciplined by the market rather than administrative regulation.

AEP Appeals 2009 Congestion Zone Designations to PUCT

AEP Energy Partners has appealed the ERCOT board's designation of 2009 congestion zones, commercially significant constraints (CSCs), and closely related elements (CREs) to the PUCT.

The board's decision to assign AEP's Oklaunion generating plant to the West congestion zone will cost AEP $35-45 million annually, from lost sales to customers in the North congestion zone. Congestion costs will no longer make the Oklaunion plant's power attractive to North zone customers on price, AEP said (Matters, 10/23/08).

AEP asserted ERCOT's board misinterpreted the relevant ERCOT Protocols in assigning the plant to the West zone, and also said contrary to past years, Oklaunion was now being singled out among baseload coal and nuclear generators as being likely to vary its output. No other coal-fired unit was deemed likely to vary its output given each's operational characteristics, AEP said.

Placing the Oklaunion plant in the West zone deprives North zone customers of its cheaper power, as the North zone has much less low-cost generation in relation to load, AEP noted.

Calif. IOUs Concerned About High Prices in MRTU Testing

Extreme locational marginal prices experienced in California ISO Market Redesign and Technology Upgrade testing is giving some stakeholders concern about a February 1, 2009 start date.

The Modesto Irrigation District filed with FERC observations made by Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric during MRTU testing, memorialized in a letter to the CAISO board.

Occasional high or low prices (prices beyond the bid caps) and price volatility are to be expected in LMP markets and are acceptable when tied to and explained by legitimate, underlying root causes, the IOUs said. However, such results, especially at extreme price levels, are not expected on a regularly recurring basis, and examination of other LMP markets shows occasions of highly volatile and extreme prices are relatively rare, the IOUs noted.

In contrast to these expectations, the IOUs have observed that MRTU market simulations are producing such prices on a regular basis. A "vast majority" of market results from September 1 through October 17 (Integrated Forward Market or IFM, Hour Ahead Scheduling Process or HASP, and Real Time Market or RTM) display extreme positive and/or negative price "outliers" that cannot be explained by either market fundamentals (gas prices, heat rates) or observable grid constraints (e.g., congestion or de-rates), IOUs reported.

A common understanding of why these relatively frequent extreme prices are occurring, as well as confidence that they should not be expected to materialize in actual production, must be obtained before the IOUs can support MRTU going live.

The IOUs also expressed concern about the Residual Unit Commitment (RUC) process and prices, as prices do not appear consistent with the intended policy and design of RUC.

RUC is designed so that resource adequacy (RA) resources not already committed in the Integrated Forward Market for a particular day are required to bid into RUC at $0/MW. RUC should have an ample supply of zero-cost capacity to meet most RUC capacity needs, and the expected result should be RUC prices at or near zero under most circumstances, IOUs said.

But the market simulation consistently produces RUC prices well above zero and often above the RUC bid cap. For example, RUC prices during the "super peak" hours from September 1 through October 16 exceeded $0/MW 95% of the time, exceeded $100/MW 30% of the time, and exceeded the RUC bid cap of $250/MW over 10% of the time, IOUs observed. RUC prices during these same hours exceeded same-hour Spinning Reserve prices from Integrated Forward Market over 95% of the time. "These observations may be indicative of a fundamental problem with RUC pricing and/or design," IOUs cautioned.

The LMP and RUC testing results show that February 1 MRTU implementation, "presents significant challenges and will become infeasible unless the CAISO is able to successfully address," the issues, IOUs concluded.

CMP Argues Net Metering Should Not Credit T&D Rates

The continued netting of both the generation and the transmission and distribution (T&D) components of a customer's bill under net metering is an "anachronism" in the era of electric energy restructuring, Central Maine Power said in comments on a Maine PUC report on net metering (Matters, 6/9/08).

"It may have made sense to allow the netting of both bill components when they were bundled prior to restructuring. However, now that 'energy' can be identified as a separate product, net energy billing credits should be limited to only energy charges," CMP said.

As the Commission has recognized that net metering is a subsidy payment from general ratepayers to distributed generation owners, such subsidization must be limited to the smallest amount possible, CMP said.

"Further, the Commission should be careful to avoid the situation where customers who can afford to purchase expensive renewable generating systems are subsidized by less fortunate customers," CMP added.

CMP opposed a proposal to expand the net metering facility cutoff limit to 500 kW from the current 100 kW, as a 100 kW facility is more than adequate to cover residential and medium-sized customers such as restaurants, retail outlets, office buildings and schools.

CMP also objected to removing the current provision requiring net metering facilities to be close to customers who claim the credits. Allowing customers to claim credit from remote generation would allow customers to obtain the additional benefit of free wheeling of electricity over a utility's T&D system, CMP noted, arguing that the PUC cannot establish terms and conditions for the wheeling of electricity over FERC-jurisdiction transmission facilities, and cannot require CMP to provide free transmission service to net energy billing customers.

Cleveland Schools Seek "Reasonable Arrangement" with FirstEnergy

The Cleveland Municipal School District petitioned for a "reasonable arrangement" with FirstEnergy's Cleveland Electric Illuminating utility, and filed a complaint asserting 2009 rates absent a reasonable arrangement or interim relief would be unjust and unreasonable.

The school district currently has a sales agreement in place with FirstEnergy that expires December 31. Barring an extension or new agreement, the schools' rates (both generation and distribution) would increase up to 94% under FirstEnergy's electric security plan, or 49% if rates were merely updated to today's tariffed rates outside of the current agreement. The hikes would total $3-4 million annually.

The school district has sought to negotiate a new agreement with FirstEnergy, but says FirstEnergy has been unresponsive. In the complaint, the school district asks PUCO to order FirstEnergy to negotiate in good faith to continue the agreement or establish a new agreement. In a request for emergency relief, the school district asks that rates in the current agreement continue pending such negotiations.

The school district also proposed a reasonable arrangement with FirstEnergy under newly enacted R.C. § 4905.31. Under the proposed reasonable arrangement, which could be recovered from all customers, including shoppers, via a nonbypassable charge, electric rates (combined generation and distribution) from the school district would remain static until May 1, 2009, then increase 5.32% for the period May 1, 2009 through December 31, 2009. Rates would increase another 4.01% for 2010, and 5.99% in 2011.

The school district argued the proposed arrangement is reasonable because the percent increases are those proposed by FirstEnergy in its pending electric security plan.

Briefly:

N.Y. PSC Seeks Comments on Two Aspects of KeySpan POR Plan

The New York PSC asked for stakeholder comments on Purchase of Receivables agreements filed by KeySpan Energy Delivery New York and KeySpan Long Island (Matters, 10/10/08). Despite a collaborative process, the appropriate calculation of the discount rate to be utilized, and the appropriate treatment of unbilled ESCO gas charges resulting from the flow of gas through the meter remain unresolved, and the PSC asked for comment on those two issues only. Comments are due November 26 (06-G-1185 et. al.)

ERCOT Files to More than Double Nodal Fee

As disclosed to legislators yesterday (Matters, 11/19/08), ERCOT applied at the PUCT to increase the nodal fee to 38¢/MWh from the current 16.9¢/MWh, effective February 1, 2009. The fee would continue to be collected from QSEs representing generation resources. The new fee would recover 75% of projected nodal monthly expenses, rather than recovering 25% of expenses as done now, with the rest financed by debt. ERCOT said the increase in percent of expenses covered by the fee is appropriate given the current state of the capital markets, noting it would be prudent to minimize debt generated by the nodal program, which currently stands at $200 million. ERCOT projects spending $12 million per month on the nodal program.

PUCT Approves Relinquishment of SGE Certificate

The PUCT accepted SGE Energy Management's petition to relinquish its REP certificate. SGE Energy Management is an affiliate of Stream Energy which had never used the certificate or served customers under the license (Matters, 10/29/08).

PUCO Defers Action of FirstEnergy MRO

PUCO deferred acting on FirstEnergy's market rate option for standard service during yesterday's Commission meeting.

BluePoint Energy Bankrupt, Liquidating Assets

Demand response provider BluePoint Energy, a trade name for Chapeau, Inc., has declared bankruptcy and announced it is liquidating all of its cogeneration and demand response assets and equipment on Nov. 24.

EnerNOC Approved by DESC

EnerNOC was selected by the Defense Energy Support Center (DESC) as an approved demand response provider.

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prices were higher during the same three-month period, which MXenergy believes will offset the expected long-term impact of higher attrition during the current quarter.

During the quarter, about 86% of all customers that received a notification of automatic renewal ultimately stayed with MXenergy, compared to the three-year average retention rate of 87% for such renewals.

Sales increased to $122.6 million from $76.0 million a year ago, with gas accounting for 65%

of sales and electricity for 35% of sales. General and administrative expenses decreased $2.2 million to $12.6 million year-over-year, due to non-recurring costs in the prior year's quarter. Advertising and marketing expenses were lower at $821,000 for the quarter, from $2.2 million a year ago, due to a shift from a multi-media marketing campaign last year to direct sales and marketing activities. Costs were also lower since much of the cost associated with direct marketing channels are deferred as customer acquisition costs on the consolidated balance sheet and amortized over a three-year estimated benefit period.

MXenergy reported that its overall liquidity position was negatively impacted from the sharp drop in natural gas market prices during the quarter, resulting in a significant reduction in the available borrowing base under the its credit facility with a consortium of banks. The reduced borrowing base strained MXenergy's ability to post letters of credit as collateral with suppliers and hedge providers, and ultimately resulted in material amendments to the agreement that governs its revolving credit facility.

Customer, Sales Data:

	Three Months Ended September 30, 2008	2007
Natural gas:		
RCEs at period end	576,000	556,000
Average RCEs during the period	586,000	579,000
MMBtus sold	5,128,000	4,433,000
Sales per MMBtu sold	$ 15.63	$ 13.64
Gross profit per MMBtu	$ .11	$ 1.18
Electricity:		
RCEs at period end	99,000	55,000
Average RCEs during the period	98,000	47,000
MWhrs sold	258,000	130,000
Sales per MWhr	$ 164.36	$ 118.96
Gross profit per MWhr	$ 15.94	$ 17.12

Gross Profit:

	Natural Gas	Electricity (in thousands)	Total
Three months ended September 30, 2008:			
Sales	**$ 80,163**	**$ 42,406**	**$ 122,569**
Cost of goods sold	**(79,618)**	**(38,294)**	**(117,912)**
Gross profit before unrealized losses from risk management activities	**$ 545**	**$ 4,112**	**4,657**
Three months ended September 30, 2007:			
Sales	$ 60,486	$ 15,465	$ 75,951
Cost of goods sold	(55,245)	(13,239)	(68,484)
Gross profit before unrealized losses from risk management activities	$ 5,241	$ 2,226	7,467

MISO Module E ... *from 1*

deficient level.

The revised proposal strikes a balance between creating incentives for sufficient capacity procurement while not encouraging overbuilding of capacity, MISO said. For the first occurrence of a deficiency, the charge reflecting the full annual CONE amount will serve as an incentive for LSEs to meet their resource adequacy obligations, and is not intended to serve as a proxy for market prices in the bilateral capacity market.

The reduced financial charges during the summer and winter months set at 25% of CONE for subsequent deficiencies reflects the greater emphasis on the need for adequate resources during higher demand months, while mitigating the cumulative impact an LSE would incur if the LSE was deficient in consecutive months. If an LSE is deficient for the entire Summer period of the Planning Year, the exposure to financial charges would max out at 150% of CONE. The proposal recognizes deficiencies in shoulder months should be penalized less severely.

MISO also presented additional evidence to justify its $80,000/MW-month CONE figure, as required by FERC's order, and compared the amount and its calculations to CONE estimates in other RTOs.

Stakeholders also filed rehearing requests on FERC's October MISO Module E order, with one of the most cited issues being the Commission's about-face on netting behind-the-meter generation against forecast load requirements.

In its October rehearing order, the Commission reversed an earlier March decision, and determined that netting behind-the-meter generation against forecast load requirements should not be permitted.

As an initial matter, the Illinois Commerce Commission and others sought clarification that FERC's decision did not extend to demand resources. Both behind-the-meter generation and demand response are considered Load Modifying Resource in MISO, and FERC's order could be read as prohibiting the netting of demand response capacity against the forecast load requirements, the ICC said.

The Michigan Public Power Agency and others further contended that eliminating the netting provision for behind-the-meter generation was not justified in FERC's order, as FERC did not provide a reason for the policy shift, or even acknowledge its explicit direction in its March order to permit netting.