Energy Choice Matters
August 6, 2008

"Unacceptable" Retail Losses Weigh Reliant

Reliant Energy posted "very disappointing" retail results as higher incremental power costs, combined with greater than expected usage from extreme heat and ERCOT congestion which prevented Reliant from bringing cheaper power into the Houston zone, reduced second quarter results by about $100 million. Other supply costs that cannot be hedged, such as ERCOT uplifts, were also higher by $50 million in the quarter, Reliant said.

Reliant posted open EBITDA, which excludes the impact of hedging, of $62 million for the second quarter, down from $193 million a year ago. On a GAAP basis, which includes the impact of derivatives, Reliant posted second quarter earnings of $358.7 million, up from a loss of $283.0 million a year ago. This quarter's GAAP earnings were lifted by $570 million in net unrealized hedging gains.

Retail contribution margin, a measure of the segment's profitability, fell by $166 million to a loss of $40 million, excluding unrealized gains/losses on energy derivatives.

Since the ERCOT market turmoil in May and June, Reliant has acquired supply to better match its load in each zone, and bought additional fixed price ancillary services in the forward market. The cost of those positions is about $55 million higher than Reliant's prior outlook. In total, Reliant lowered its retail outlook for the year by about $240 million.

Reliant benefited from a decision late last year, made in response to some congestion issues and wind generation, to reduce its seller's choice position, and has avoided about $25 million of additional costs as a result.

Customer count was down by 102,000 year-over-year to just under 1.77 million. Compared with the year-ago quarter, Reliant lost 78,000 Houston area residential customers, 24,000 non-Houston residential customers, and 8,000 Houston area small business customers. Reliant picked up 4,000

... Continued Page 5

Connecticut EDCs Issue Long-Term Contract NOI to Prep for Future RFP

Connecticut Light & Power and United Illuminating issued a Notice of Interest to explore opportunities for long-term power contracts to serve their standard service customers.

The NOI seeks information on market products and new and existing generation to help develop a procurement plan and comprehensive RFP for long-term power supply. Though a schedule has not been set, the utilities anticipate releasing an RFP during this fall.

A DPUC decision in April opened the door for the EDCs to procure up to 20% of the EDCs' standard service load on long-term contracts (Matters, 4/4/08), which is approximately 3.85 million MWh of energy and 885 MW of capacity between CL&P and UI.

The utilities are interested in contracts lasting at least three years to commence on or after January 1, 2010. Products may be physical or financial, and may bundle energy and capacity or be separate. Market products not tied to specific generating facilities must be 25 MW or larger, while specific generation projects must be capable of qualifying as Large Generating Facilities (larger than 20 MW) under ISO New England's OATT. Both criteria include exceptions for CT Class I and II renewables, which may be of any size.

Because the DPUC does not allow the EDCs to buy RECs on the same long-term contract as energy or capacity, the utilities reported that they will pursue the procurement of RECs through a different process, and are not seeking REC proposals in response to the current NOI.

The EDCs prefer to receive more detail as opposed to less from responding market participants,

... Continued Page 6

BGE Withdraws Flexible Load Response Payment Plan in Response to EnerNOC Concerns

Baltimore Gas & Electric withdrew a request to institute a flexible revenue sharing mechanism for customers in its load response program for which it is acting as the curtailment service provider (Rider 24) after EnerNOC raised competitive concerns about the revenue sharing mechanism.

BGE had proposed changing its curtailment service payment structure so that it would pay customers a minimum of 80% of their PJM revenues, with the discretion of also sharing additional amounts above that 80% with customers. Currently, BGE's tariff calls for 80% to be paid to the customer, with BGE keeping 20% for program expenses.

The problem, EnerNOC noted, is that BGE had also proposed to offer billing services to third-party curtailment service providers, under which a customer's curtailment revenues would be credited on their BGE bill, minus a $70 administrative fee per billing transaction. Curtailment service providers would remit a customer's PJM revenues to BGE for the funds to be applied to that customer's BGE bill.

BGE had recommended the on-bill credit program due to demand from governmental customers. The utility had also reasoned that bill credit compensation may encourage submetered locations, such as shopping malls, to participate in load response programs.

But EnerNOC is concerned that with access to confidential third-party billing information provided to BGE by curtailment service providers as part of the bill-credit program, BGE could change its revenue sharing percentage for its own load response customers in response to that competitive information.

BGE agreed that such a scenario is a "valid concern" though it assured the Maryland PSC that it would have never executed the program in such a manner.

"However, the perception alone of this potential activity is enough for BGE to reconsider its proposed revisions in order to avoid disrupting the demand response market," BGE said, noting that third-party demand response providers could reduce their offerings in Maryland as a result of the perception.

Thus, BGE withdrew its request to have flexibility in curtailment service revenue payments to customers, and proposed keeping the billing services option for third-party curtailment service providers.

WGES Profits Fall on Lower Margins

Lower margins from both electric and natural gas sales decreased net income at Washington Gas Energy Services to $8.1 million for the third fiscal quarter, down from $16.0 million a year ago, on a GAAP basis. Excluding the impact of derivatives, quarterly earnings were $5.1 million, down from $12.7 million a year ago.

On the electricity side, WGES encountered decreased sales volumes due to a reduction in the number of commercial customers and lower margins per kilowatt sold, primarily as a result of weather experienced during June 2008 and unfavorable electric supply prices. For competitive natural gas sales, lower margins reflected decreased sales volumes due to a reduction in the number of large commercial accounts and higher prices incurred for the purchase of natural gas.

Natural gas customer count fell to 138,200 from 143,100 a year ago. WGES reported natural gas sales of 111.8 million therms in the quarter, down from 131.0 million therms a year ago. Electric customers grew to 63,600 from 62,400 in the year-ago quarter. Quarterly electricity sales were 854.3 million kWh versus 985.6 million kWh a year ago.

Washington Gas Energy Systems, WGL's HVAC and energy service company, reported $301,000 in net income, compared with $37,000 a year ago.

Parent WGL Holdings recorded a quarterly GAAP loss of $492,000 compared to net income of $13.0 million in the year-ago quarter.

OCC Suggests "Not Greater Than Rate" for Ohio Renewals

The Ohio Consumers' Counsel suggested that the first notice retail gas marketers send to customers facing automatic renewal could list a "not greater than rate" to alleviate concerns that requiring a price to be listed in the first of two renewal notices could raise renewal prices to customers because of increased risk in keeping an offer open a longer period of time (08-724-GA-ORD).

PUCO Staff have proposed requiring marketers to include the renewal rate in the initial 45-day notice marketers must send to customers with contracts that automatically renew for six months or more, have a material change, and have a termination fee of $25 or less. Currently, the rate must only be contained in the second, 20-day notice.

Marketers cautioned that forcing the renewal rate to be listed 45 days ahead of renewal will raise prices because of the premium associated with time and potential volatility (Matters, 7/28/08), and urged that the current rule be maintained.

In reply comments, the OCC disagreed that a shorter notice period for the new rate is in the public interest.

However, OCC suggested that the renewal rate in the 45-day notice could be a "not greater than rate" that would give customers a benchmark for shopping, but could be lowered in the second, 20-day notice if conditions warrant. OCC noted that consumers contacting the agency "routinely" express the need for timely and accurate pricing information; thus including the rate in the 45-day notice is appropriate.

OCC also endorsed Staff's proposal that only variable rate contracts with a specific pricing formula, rather than just a description of the factors which determine price, be allowed to include an early termination fee. OCC argued that customers may lack sufficient information to compare offers when a formula is not provided.

Marketers opposed OCC's suggestion that changes in a supplier's ownership or operating business plan should constitute a material change for purposes of contract renewal disclosures.

Dominion Retail noted that OCC's language is ambiguous, leaving the supplier to guess as to what constitutes "any substantive change ... within a company's ownership or operating business plan." The Ohio Gas Marketers Group pointed out that, technically, ownership changes anytime a share of stock is sold, and added that business plans change daily. Dominion Retail also observed that the requirements go beyond the information that must be included in the initial contract offer.

OCC opposed the Ohio Gas Marketers Group's recommendation that relocating customers should only be allowed to avoid termination penalties when moving to another LDC service area, or where the LDC cannot accommodate maintaining the contract if moving within the same service area, since some LDCs can now accommodate contract portability.

OCC also suggested ditching the overly complex quid pro quo rules regarding when marketers and customers have the right to unilateral contract termination without either having to pay the other party a fee, or giving the other party that same unilateral right. OCC recommended simply that any relocating customer be allowed to terminate a contract without penalty, and that marketers be allowed to terminate without penalty due to force majeure.

PUCO Sets ESP Schedules

PUCO has issued a staggered schedule to review the Electric Security Plans proposed by the state's electric distribution utilities, with evaluation of FirstEnergy's ESP to occur first since the utility no longer has generation and thus is most in need of having new supply arrangements in place by Jan. 1 2009 when current stabilization plans expire (Matters, 8/1/08).

Duke Energy Ohio's ESP (08-920-EL-SSO) would be evaluated next, followed by AEP's (08-917-EL-UNC).

PUCO will hold a technical conference addressing both FirstEnergy's electric security plan and market rate offer on Aug. 18. Testimony on the ESP (08-935-EL-SSO) is due Sept. 15 with an evidentiary hearing on Oct. 2. A procedural timeline for the MRO (08-936-EL-SSO) has not been set.

For Duke's ESP, a technical conference will be held Aug. 21, with testimony due Oct. 3 and an evidentiary hearing on Oct. 20.

A technical conference on AEP's plan would be held Aug. 19, with testimony due Oct. 17 and an evidentiary hearing on Nov. 3.

Darbee Could Temporarily Serve as Two CEOs Under Calif. Draft

A draft California PUC decision would grant on an interim basis the request of Pacific Gas and Electric to have CEO of parent PG&E Corp. Peter Darbee concurrently serve as CEO of the utility and parent corporation, necessitating a waiver of certain Commission affiliate rules (A. 08-07-014).

PG&E had asked for the waiver for as long as its parent does not have significant non-regulated subsidiaries, but that question will be decided in a future decision.

The draft released yesterday would allow Darbee to serve as the utility and parent CEO while the case is litigated, for a maximum of 120 days.

A temporary waiver it appropriate, the draft finds, because a temporary CEO would not have lasting authority to enforce decisions. The PUC intends to review the existing reporting relationships among employees and officers between the holding company and the utility when evaluating the waiver on a non-interim basis. The temporary waiver does not set precedent, the draft stressed.

The Independent Energy Producers Association had not objected to the temporary waiver, but is concerned about PG&E's proposal to keep a shared CEO until certain affiliates constitute 5% of PG&E Corporation's consolidated assets or generate 5% of PG&E Corporation's consolidated operating revenue.

IEP recommends that any waiver ultimately granted should be re-evaluated periodically when new affiliates are created, when new affiliate compliance plans are filed, and during regularly scheduled biennial audits.

Briefly:

MXenergy Acquiring Commerce Energy BGE Gas Customers

Commerce Energy is transferring all of its natural gas customers in the Baltimore Gas & Electric area, about 500 residential accounts, to MXenergy, expected to be effective October 1. MXenergy will honor existing pricing and terms for the remainder of the contracts.

MRTU Delayed Until at Least Feb. 2009

The California ISO disclosed yesterday that a fall 2008 implementation date for the Market Redesign and Technology Upgrade is no longer feasible based on, "challenges recently experienced in Integrated Market Simulation Update 2 (IMS Update 2)," as well as stakeholder feedback. Because market participants do not favor a December or January implementation, the earliest implementation would likely be February 2009, though CAISO does not have a new implementation date set at this time. While CAISO has now validated 91 of 125 charge codes, the previously observed levels of performance of the Day-Ahead Market (DAM) and Real-Time Market (RTM) have deteriorated. Recently, DAM results were not published within the MRTU Tariff-specified market timeline on several days, after having previously been published mostly on time for several weeks. Completion of the DAM run has on numerous occasions required that specific iterations and/or market functions be disabled in order to reach a solution, CAISO told FERC in a monthly update (ER06-615).

Pepco Energy Services Taps John Glynn for New England Growth

Pepco Energy Services named John Glynn as Regional Energy Manager for New England to enhance the retailer's expansion into the New England energy market. Glynn is a veteran of Direct Energy and Select Energy.

DC Energy Entering Texas

DC Energy Texas, a subsidiary of one of the more active financial marketers in eastern RTOs, submitted a registration as a power marketer in Texas to the PUCT.

Hearing Set for Md. PIP

The Maryland PSC set a hearing for Aug. 27 to review Staff's SOS Procurement Improvement Process Report as well as any non-consensus recommendations, such as Baltimore Gas and Electric's proposal for seasonally shaped prices (Matters, 8/4/08). Comments on the report and non-consensus items are due Aug. 15.

D.C. PSC OKs Pepco Withdrawal of Panda Account Application

The District of Columbia PSC approved Pepco's request to withdraw its application to place $320 million in a special purpose account that was to have been used solely for the purpose of paying above-market costs of the Panda-Brandywine PPA. Pepco has since reached an agreement to transfer the Panda PPA to Sempra Energy Trading (FC945, Matters, 6/24/08).

IPPNY Sees Development Barrier in Revised Interconnection Fee

The Independent Power Producers of New York protested that the New York ISO's proposal to convert a developer's initial refundable deposit associated with an initial interconnection scoping meeting into a payment for meeting with the affected Transmission Owner and NYISO would merely shift costs to potential generation developers and does not improve the interconnection process (ER08-1272). The conversion of the deposit to a $10,000 payment will not expedite the interconnection process, IPPNY argued, and is solely an issue of cost recovery. The change will likely create one more impediment to developers seeking to construct new power plants in New York, IPPNY added. In some cases, the initial meetings serve to inform developers whether the proposed interconnection point is even technically and economically viable ahead of the completion of an interconnection study. While such information has thus far been free, it would cost $10,000 under the changes, IPPNY explained, serving as a barrier to development.

ISO-NE Plans Oct. 31 Filing of Revised Queue Process

ISO New England reported to FERC it will submit tariff revisions to address the redesign of the Interconnection Queue Process by October 31, about a month later than the ISO's earlier Oct. 1 commitment (ER07-546-001). The additional time is needed to draft "extensive" tariff revisions and permit stakeholder review, ISO-NE said. A term sheet was approved by the NEPOOL Participants Committee on August 1, the ISO added.

Duke Commercial Power Unit Sees Higher Profits

Duke Energy's Commercial Power unit reported second-quarter EBIT from continuing operations of $235 million, compared to $64 million in the second quarter 2007. Adjusted EBIT, which excludes hedging impacts, rose to $128 million for the quarter, compared to $42 million a year ago. The earnings growth was due primarily to gains on the sales of emission allowances, lower purchase accounting expenses and improved rate stabilization plan rider collections. A $4 million improvement at Duke's Midwest gas-fired assets also contributed to the results. While the units posted an adjusted EBIT loss of about $1 million, Duke reported that it continues to see improvement in the assets and expects them to be EBIT positive on an adjusted basis by 2009. Duke updated analysts on its wind strategy and reported that it expects have approximately 500 MW of wind power in operation by 2009 with a development pipeline of more than 5,000 MW in 12 states. Duke expects to bring 200-300 MW of wind online annually. Parent Duke recorded higher net income of $351 million versus $293 million a year ago.

FERC Approves RPM Third Incremental Auction Settlement

FERC accepted a settlement between Mirant, PJM and other stakeholders that modifies PJM's Tariff such that for RPM's Third Incremental Auction only, the Market Seller Offer Cap for an existing generation resource shall be, at the election of such resource, (a) the avoided cost rate; (b) the documented price available to an existing generation resource in a market external to PJM; or (c) 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant Locational Delivery Area and Delivery Year (EL08-8). Mirant had argued that the Market Seller Offer Caps did not reflect sellers' risk of being subject to deficiency charges, and, combined with market participant knowledge that all sellers are being mitigated, would result in Third Incremental Auction prices significantly below those that would otherwise have resulted from a workably competitive market.

Reliant Energy ... from 1

small business customers in non-Houston areas, and another 4,000 customers in its large C&I segment, compared with a year ago.

However, Reliant reported that it has acquired 25,000 customers since May, calling it a "dramatic turnaround," and attributing the gains to its additional marketing efforts as well as gains from defaulting REPs. Total quarterly sales were 17.9 TWh, up from 16.8 TWh a year ago.

Mass market retail gross margin dropped from $201 million a year ago to $66 million in the second quarter, or from $30.58/MWh to

$10.09/MWh. C&I gross margin fell from $52 million to $1 million year-over-year, or from $5.08/MWh to $0.09/MWh.

Quarterly selling and marketing expenses grew $8 million to $38 million, while bad debt fell to $6 million from $21 million a year ago.

Retail revenue rose to $2.4 billion from $2.0 billion in the year-ago quarter.

Reliant's wholesale unit recorded a strong quarter with open wholesale contribution margin rising to $142 million from $118 million a year ago on improved plant availability and better unit margins generated by tightening supply and demand fundamentals and higher commodity prices.

Commercial capacity factor for the quarter rose to 85.9% from 75.4%, boosting results by $17 million. "Solid" June power prices lifted open energy unit margin to $32.04/MWh ($202 million gross margin) versus $24.33/MWh ($197 million gross margin) in the prior-year quarter. Reliant also saw a $10 million improvement in "other" margin, mostly from improved capacity payments in PJM.

COO Brian Landrum reported that depressed heat rates which have persisted, especially in the off-peak periods in PJM and particularly in MISO, aren't sustainable. A "modest" decrease in Reliant's economic generation during the quarter was attributed to the lower heat rates.

Landrum reported that the depressed heat rates look like uneconomic bidding behavior by some coal generators, who were setting the price during off-peak hours, especially in MISO.

"When we look at those off-peak spreads, we don't think those numbers reflect the market price of the coal, and so we can't say why a generator would choose to run their plant at a lower return, than they would earn by not running the plant and selling the coal. It seems to us that this approach and resulting off-peak spreads aren't sustainable," especially if supply and demand start to tighten, Landrum said.

Conn. NOI... from 1

and encouraged respondents to provide indicative pricing as of the submittal date of September 15, 2008. The utilities also encouraged respondents to provide multiple product and pricing options (e.g. fixed, floating-fixed, floating, index based pricing, or cost-of-service) as well as their preferred contract structure (PPA, Contract for Differences, ISDA, etc.).

The utilities see long-term contracts as an opportunity to provide greater stability in retail rates and "best minimize future power supply costs."

The DPUC has not yet ruled on how long-term contracts would be integrated into the EDCs' procurement of full requirements contracts for standard service, and the Department has stated that it will defer ruling on that issue until it is presented with a contract for approval.

While the "primary intent" of the NOI is not to proceed directly to one or more contracts outside of the RFP process, the utilities, "cannot rule out the possibility of proceeding with bilateral negotiations if presented with one or more actionable proposals that provide very clear and substantial benefits for customers."

NOI info is available at www.uinet.com/powerprocurement and www.cl-p.com/esupplier/wholesale.asp.