Energy Choice Matters
August 11, 2009

UI Says No Corrective Actions Needed for Electric Supplier Marketing

United Illuminating has not had any customer calls or complaints to its customer service center regarding competitive supplier and aggregator marketing practices that require "corrective actions" by the Connecticut DPUC, the utility said in an interrogatory response, as issues which have arisen have been resolved informally with suppliers (Matters, 8/10/09).

As only reported by *Matters*, the DPUC has sent interrogatories to all licensed suppliers and the distribution utilities regarding supplier marketing.

UI reported that with the increase in customer switching and apparent increases in supplier marketing activity, customer inquiries regarding competitive suppliers have increased. UI recently instituted a process to forward a record of such calls to its Supplier Relations department for monitoring supplier activity and for possible follow-up with the supplier or the DPUC.

"The majority of supplier related calls have been from customers questioning the validity of a supplier's claims (lower prices, better deal, saving money) and whether the supplier is a valid entity. Some customers have complained that suppliers have represented that they are UI employees. Some customers have said that they are being told that 'UI is charging them too much and they should switch to a lower cost provider.' Some are still unaware that 'retail choice' is available in CT and wonder why someone wants to sell them electricity," UI reported.

UI said that its Supplier Relations team contacts retail suppliers if it receives a customer complaint/inquiry that may indicate questionable marketing activity, potential customer confusion, or at the request of the customer. UI informs the supplier of the nature of the complaint/inquiry, and asks the supplier to review its marketing protocols.

"Suppliers have been receptive to this input and have agreed to follow-up with their marketing staff.

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N.Y. Draft Energy Plan Favors Expansion of Dynamic Pricing, Bilateral Green Contracts

The New York PSC, "should be authorized to require that electricity be priced on a time of use basis for all customers, upon a finding that it is in the public interest to do so," a draft state energy plan says. The draft, now subject to public comment, is the product of the New York State Energy Planning Board, created by Gov. David Paterson last year.

Issues that should be considered in determining whether time of use prices should be mandatory should include: (1) the practical hardships and difficulties related to implementing time of use rates for residential customers; (2) possible means to mitigate any such hardships; and (3) alternative rate regimes, based on voluntary participation of residential customers, the draft said.

Furthermore, the draft recommends that policymakers, "should broaden the installation of advanced meters and implementation of mandatory hourly pricing for industrial and commercial customers by continuing to reduce the demand thresholds [for mandatory hourly pricing]."

The draft concluded that dynamic rate design coupled with advanced meters would facilitate informed decision-making and help reduce customer energy bills. "Providing electricity pricing information to consumers at the time consumption decisions are being made, and charging

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Superior Plus Reports Slight Drop in Energy Marketing EBITDA from Operations

Superior Plus reported EBITDA from operations for its fixed-price energy services unit of $2.8 million for the second quarter, down slightly from $3.1 million a year ago (all figures Canadian). On a GAAP basis, Superior reported earnings of $17.6 million for the quarter, down from $145.1 million a year ago, as the prior-year quarter saw higher unrealized hedging gains of $142.1 million, versus $14.8 million for the 2009 quarter.

Gross profit for the retailer was $8.3 million versus $8.6 million a year ago (see gross profit breakdown at bottom of page).

Natural gas sales volumes were modestly higher than the prior-year quarter as an increase in commercial volumes more than offset the impact of reduced residential customer volumes. As only reported in *Matters*, Superior said at the end of the first quarter it was suspending residential marketing in Ontario and shifting to a commercial focus due to the lack of a value proposition in the residential market (Matters, 5/11/09). Superior continues to focus its sales channels towards acquiring and retaining Ontario commercial natural gas and electricity customers, Quebec commercial natural gas customers, and British Columbia residential and commercial natural gas customers

Higher electric volumes reflected the continued aggregation of commercial customers over the past twelve months as well.

Superior ended the quarter with a customer base of 89,900 residential natural gas customers, 6,400 commercial natural gas customers and 4,700 electricity customers. Compared to the quarter ending March 31, 2009, residential gas accounts were down 1,400; commercial gas accounts were flat; and electric accounts were up by 300.

About 28% of volumes are residential and small commercial customer sales, down from 29% a year ago. Superior invested $1.2 million in customer acquisition costs during the second quarter.

Quarterly revenues were down at $77.4 million from $85.6 million a year ago, while cost of sales was lower was $69.1 million versus $77.0 million a year ago. Operating, administrative and selling costs were flat at $5.5 million.

Dynegy to Sell 4,800 MW to LS Power

Dynegy will sell about 4,800 MW of generation assets to LS Power for $1 billion in cash and $500 million in stock in a move to boost liquidity and pare down debt, further unwinding a partnership which launched in 2006.

Additionally, the transaction will also eliminate Dynegy's dual-class stock structure and associated Class B rights and restrictions, with LS Power's stake in Dynegy shrinking from about 40% to 15%. Dynegy CEO Bruce Williamson said that the agreement will finally make Dynegy a fully public company, which will provide more freedom through greater strategic and financial flexibility. The removal of the Class B rights and restrictions is seen by analysts as eliminating a previous impediment to consolidation at Dynegy.

Included in the sale are five gas-fired peaking plants (Riverside and Bluegrass in Kentucky, Rocky Road and Tilton in Illinois, and Renaissance in Michigan), three combined cycle facilities (Arlington Valley and Griffith in Arizona and Bridgeport in Connecticut), and Dynegy's interest in the Sandy Creek (ERCOT) project, currently under construction.

The assets represent about one quarter of Dynegy's fleet, and the transaction will leave Dynegy with about 13,000 MW of generation.

Upon closing the sale, Dynegy said that 43 percent of its portfolio will be located in the Midwest, 32 percent in the West, and 25 percent

Superior Gross Profit Detail *(millions of dollars)*

	Three months ended June 30, 2009			**Three months ended June 30, 2008**		
	Gross Profit	Volume	Per Unit	Gross Profit	Volume	Per Unit
Natural Gas	8.00	8.3 million GJ	96.4 ¢/GJ	8.35	8.0 million GJ	104.4 ¢/GJ
Electricity	0.30	38.1 GWh	0.79 ¢/kWh	0.25	13.9 GWh	1.79 ¢/kWh
Total	8.30			8.60		

in the Northeast. Post transaction, 34 percent of Dynegy's generating capacity will be natural gas-fired combined-cycle capacity, 25 percent will be natural gas-fired peaking capacity, 31 percent will be baseload coal/fuel oil capacity and 10 percent will be dual fuel capacity.

Dynegy said that the assets sold have limited upside potential, as the peakers, which constitute 60% of the transaction portfolio, have typically been marginal, while two of the combined-cycle units have long-term contracts that expire in 2017 or later. Adjusted EBITDA of the traded asset group is expected to be approximately $70 million in 2009 and approximately $140 million in 2010. Adjusted EBITDA doubles primarily due to a toll that goes into effect at the Arlington Valley plant and some higher capacity payments, though Dynegy said further upside is limited.

Dynegy called the post-transaction asset mix more attractive than its fleet prior to acquiring the assets from LS Power in 2007. Before 2007, Dynegy had one combined cycle asset, with its fleet essentially a "barbell portfolio" of baseload coal and peakers. The 2007 LS Power acquisition added seven CCGTs, while the post-sale Dynegy will still maintain five CCGTs.

Following the close of the transaction, Dynegy expects to have approximately $3.0 billion in liquidity, including approximately $1.9 billion in cash on hand.

For the second quarter, Dynegy reported lower adjusted EBITDA of $125 million, down from $184 million a year ago, due to lower realized power prices partially offset by higher production volumes from the company's Midwest and Northeast combined-cycle units. The quarterly net loss attributable to Dynegy Inc. was higher at $345 million, versus a net loss of $272 million a year ago. In addition to depressed power prices, asset impairment charges drove the wider net loss.

Dynegy's Midwest assets reported an operating loss for the quarter of $85 million, narrowed from $170 million a year ago. Production increased approximately 10 percent due to lower natural gas costs and higher market-implied heat rates that benefited the company's Kendall and Ontelaunee facilities in Illinois and Pennsylvania, respectively. Coal-fired generation was flat period-over-period due to mild spring weather.

The company's West assets recorded operating income of $37 million versus an operating loss of $32 million a year ago, reflecting increased tolling revenue, partially offset by lower realized spark spreads. Production decreased approximately 40 percent due to mild June weather and an extended outage that reduced volumes at the Moss Landing facility in California.

Dynegy's Northeast assets saw an operating loss of $382 million versus $142 million a year ago. Production increased approximately 30 percent due to higher volumes at the Casco Bay and Independence facilities due to improved spark spreads. The Danskammer and Roseton facilities were impacted by higher fuel and emission costs that reduced dispatch opportunities.

NYISO Says Stakeholders Favor No Restitution for January 2008 PAR Modeling Error

The New York ISO reported to FERC that there is "stakeholder consensus" that restitution to correct values incorrectly introduced into the NYISO's Security Constrained Unit Commitment software for the Waldwick-Ramapo Phase Angle Regulator (PAR) for several days in January 2008 is not reasonable, for a variety of factors. NYISO's comment came in a final report on a stakeholder process which examined whether restitution is feasible.

The NYISO originally asked for various waivers at FERC so that it would not have to reconstruct market outcomes to correct for the Waldwick PAR error. However, several load serving entities negatively affected by the error have sought some form of "rough justice" restitution (recognizing that perfect resettlement is not possible) based on NYISO estimates of the modeling error's impact.

LSEs such as NYSEG, Rochester Gas & Electric, and various municipals noted that the harm from NYISO's modeling error was not evenly distributed throughout New York State. The incorrect PAR inputs resulted in the redispatch of generation, causing an increase in Locational-Based Marginal Prices west of the Total East interface, and a decrease in LBMPs east of Total East. The error caused certain western LSEs to pay in the aggregate $10.5 million in balancing congestion residuals.

NYSEG, RG&E, and the munis recommended that the negatively impacted LSEs be partially reimbursed for the $10.5 million using $3.5 million in congestion rents received by other LSEs due to the error.

NYISO, however, said that there is no stakeholder support for the western LSEs' rough justice solution, aside from those offering the plan. No alternate restitution proposals were offered.

Virtually all stakeholders speaking at a July 29 meeting (and most stakeholders speaking at preceding meetings) opposed efforts to devise a restitution methodology to address the impacts of the Waldwick PAR error, albeit for different reasons, NYISO added. Such reasons included the importance of price finality, and the complexity of correcting the PAR error, as any effort would (i) require the NYISO to make numerous assumptions as to how market participants would have behaved had the errors not occurred; (ii) the need to account for potential impacts on market participants' NYISO Transmission Congestion Contract positions, NYISO energy import/export transactions, and other hedging strategies and derivatives, etc.; and (iii) any correction would constitute an effort to reconstruct the LBMP outcomes in the NYISO energy markets, a type of effort often disfavored in FERC precedent.

"Further, it is not possible to know what the 'correct' LBMPs would have been had the correct inputs been used, because the incorrect Waldwick PAR inputs directly affected market participants' subsequent bid and offer behavior," NYISO said in reiterating its waiver request.

FERC Denies Rehearing Requests on Short-Term Capacity Release Refunds

In three similar cases, FERC denied rehearing requests from retail gas suppliers who argued that Commission policy regarding refunds related to short-term capacity release transactions will place retail marketers at a competitive disadvantage to LDCs.

In Order 712-A, FERC removed the price ceiling for all short-term capacity releases of one year or less. Accordingly, a capacity release transaction of one year or less has a market-based rate instead of the regulated cost-based rate. "Thus, because the pipeline's maximum rates do not apply to short-term capacity release transactions ... replacement shippers are not entitled to any refunds when the Commission finds that the maximum rates proposed by a pipeline in a section 4 rate case are too high," FERC had held.

Several suppliers, including BP Energy and Hess Corporation, protested compliance filings made by Texas Eastern Transmission, Maritimes & Northeast Pipeline, and Algonquin Gas Transmission regarding FERC's refund policy. Consistent with FERC's order, the pipelines submitted tariff language which held that for releases that become effective on or after July 30, 2008, any rate paid by a replacement shipper in any capacity release transaction with a term of one year or less which is not subject to the maximum rate cap is deemed to be a final rate and is not subject to refund.

Under such a policy, any refund would flow to the releasing shipper. The suppliers' protests were initially denied in a December order, of which the suppliers sought rehearing.

The suppliers reiterated that in states with retail gas unbundling, replacement shippers effectively step into the shoes of regulated LDCs to provide the gas supply requirements of retail consumers. The pipelines' tariffs, suppliers said, would allow the LDCs to reap the benefit of a windfall from any refunds, even though the marketers are bearing financial responsibility and paying the LDCs' pass-through rate for the capacity.

The suppliers further noted that while short-term capacity releases have a market-based rate, pre-arranged short-term releases under a state retail unbundling program are not subject to bidding, and consequently do not reflect the short-term variations in the market value of the capacity.

Under the pipelines' refund policy, retail marketers will not be able to compete with LDCs to serve retail gas customers because the marketers will be required to pay a higher rate than the LDC for the same capacity, suppliers added.

FERC called the protests collateral attacks on Order 712-A and dismissed the rehearing requests as improper. FERC further said that the suppliers ignore the fact that LDCs are regulated by state commissions, and that any refund proceeds would be disposed of under such state regulations.

New Brunswick Power Generation Submits Maritimes Market Power Analysis

New Brunswick Power Generation submitted a compliance filing at FERC containing a horizontal market power study of the New Brunswick System Operator balancing authority area, arguing that it does not possess horizontal market power (EL09-32). New Brunswick Power Generation was ordered to submit the test to maintain its market-based rate authority, stemming from a compliant originally filed by Integrys Energy Services (Matters, 6/11/09).

Under its filed analysis, New Brunswick Generation passes the Pivotal Supplier Test but fails portions of the Market Share Test (though with indicated market shares consistently below 30 percent). Per FERC precedent, sellers failing one of those tests are permitted to show that they lack market power by presenting a Delivered Price Test (DPT) analysis.

New Brunswick Generation submitted a Delivered Price Test analysis for the New Brunswick System Operator balancing authority area and Maritimes balancing authority area, which New Brunswick Generation said demonstrates a lack of horizontal market power in both markets.

While the tests indicate a high Economic Capacity measure, New Brunswick Generation said that the Economic Capacity measure fails to take into account an entity's load obligations which, in the case of load serving entities like Generation's affiliate New Brunswick Power Distribution, are very significant. New Brunswick Power Distribution has seasonal peak load obligations ranging from approximately 1,750 MW during peak summer periods to approximately 2,850 MW during the winter extreme-peak period.

The Available Economic Capacity measure indicated one period in which New Brunswick Generation's market share exceeds 20 percent -- the winter, off-peak period (both for the New Brunswick System Operator BAA and Maritimes BAA). "During this period, loads are relatively low and generation is relatively plentiful and elastic in supply. It would thus, by definition, be almost impossible for NBP Generation to exercise market power in such off-peak hours, regardless of the market share percentage indicated by the DPT results," New Brunswick Generation argued.

Briefly:

Continental Energy Group Seeks Ohio Broker License

Continental Energy Group, LLC applied for a broker/aggregator license at the Public Utilities Commission of Ohio, to serve all customer classes in all service territories. Texas-based Continental was formed in 2007 and initially focused on the ERCOT market, but has since been evaluating emerging markets.

Watt2Choose Receives Texas Aggregation License

The PUCT granted Watt2Choose, LLC an aggregator certificate. Several of Watt2Choose's principals are partners are SBL Systems, a firm that offers Control System Engineering and other automation services to manufactures and other industrial customers (Matters, 7/21/09).

MXenergy Extends Exchange Offer Deadline Again

MXenergy Holdings again extended the expiration date for the Exchange Offer and Consent Solicitation (until midnight August 13) of its outstanding Floating Rate Senior Notes due 2011 to provide additional time for ongoing negotiations with the contemplated provider of its proposed new credit, hedge and supply facilities. The exchange offer is integral to MXenergy's restructuring plan (Matters, 7/2/09).

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To date this process has resolved all known issues," UI said.

Accordingly, UI said that current actions are appropriate and did not recommended any additional actions to be taken by the DPUC. If a problem persists or if a supplier or aggregator does not investigate, follow-up, or modify their solicitation protocols to resolve customer issues, then UI said it would forward such complaints to the DPUC.

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consumers accordingly, would enhance economic efficiency, assist consumers in managing their energy use and controlling their bills and could help reduce system peaks," the draft says.

The draft also recommended that, in addition to the current RPS solicitation process, renewable power should be procured bilaterally.

The Long Island Power Authority and New York Power Authority, "with utilities and other partners," should proceed with issuing an RFP for the private development of offshore wind resources under power purchase agreements, the draft recommends. The draft does not address, should a utility be party to a PPA, how such power would be allocated to its customers.

The draft also encourages the state's power authorities to procure diverse renewable electricity supplies, including solar, onshore and offshore wind, hydrokinetic, and sustainably managed biomass, via bilateral contracts.

The draft praises the operation of the New York ISO competitive market as making the state's electric system more efficient. Several state lawmakers have heavily criticized NYISO's uniform clearing price auction.

"The market's locational prices have provided transparent price signals that in a competitive environment have induced investment in newer and more efficient generation, as well as new transmission and demand response resources, in the locations where the resources are most valued," the draft concludes.

The draft finds that NYISO's market structure provides an economic incentive for power plant operators to run as efficiently as possible. Average plant availability in New York increased from 87.5 percent in the 1992 to 1999 timeframe to 94.4 percent in the 2000 to 2007 timeframe, the draft notes.

Additionally, the gross heat rate of New York's power plant fleet has been trending downward since the late 1990s, indicating a continuing improvement in the overall efficiency of the state's electric generation, the draft notes. NYISO has calculated that since 1999, New York's gross heat rate has improved 21 percent. "The State's markets and its commitment to continually improve them will facilitate this substitution," by relying on new, more efficient plants to replace older, less efficient plants.

The draft attributes New York's relatively high energy price not to a uniform clearing price, but rather to, "the State's heavy reliance on fossil fuels from out of State, relatively low dependence on coal which is a lesser expensive fuel, electricity system constraints, natural gas and petroleum product transmission and pipeline system constraints, the State's geographic location away from major supplies of energy, and State and local taxes and fees."

The draft also recommends a new siting law for power plants.