Energy Choice Matters

August 3, 2010

Allegheny Power Not Including Transmission Rate in SOS Supply Information

Allegheny Power has interpreted the Maryland PSC's order on SOS Supply Price Comparison Information to be included on bills as excluding the transmission component from the rate information, but has asked that it be permitted to include the transmission rate as a separate line item. Baltimore Gas & Electric and the Pepco utilities have interpreted the Commission's language as including the transmission rate in the comparison information (Case 9228, Matters, 6/25/10).

In June, the PSC ordered all SOS bills to include the following language as part of a revised mechanism to provide customers with SOS pricing information:

"Supply" Price Comparison Information: The current price for Standard Offer Service electricity is x.x cents/kWh, effective through [date]. Standard Offer Service electricity will cost x.x cents/kWh beginning on [date] through [date]. The price of Standard Offer Service electricity after [date] has not yet been set. The weighted average price of Standard Offer Service electricity will be x.x cents through [date].

In a compliance filing, Allegheny has indicated that it is not including the bypassable transmission rate in the rates listed under this disclosure. In the disclosure listed on customers' August bills, the rate only includes the "electric supply charge" component of Allegheny's SOS charge, which excludes transmission.

Allegheny agreed that customers should be provided with the bypassable transmission rate to fully understand the available shopping credit, and thus asked the PSC for approval to add the following to bills: "The SOS price plus the Transmission price of 0.396 cents/kWh equals the Price to Compare."

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Reliant Comparative Earnings Fall on Lower Margins from Pricing, Attrition

Reliant Energy reported net income of $277 million for the second quarter of 2010, compared with net income of $233 million for the months of May and June 2009, as Reliant continues to experience attrition in its customer base despite a lower pricing strategy which has reduced mass market margins.

Second quarter adjusted EBITDA, excluding mark-to-market, totaled $195 million, versus $230 million for the period May through June 2009. NRG completed the Reliant acquisition on May 1, 2009.

Although second quarter 2010 margin levels were still strong driven by a low commodity environment, Reliant saw an $86 million decline in retail gross margin in the months of May and June 2010, with the 2010 gross margin equaling $234 million versus $320 million for May and June 2009. For the full three months ending June 30, 2010, gross margin was $308 million.

The lower gross margin resulted from a 22% decrease in mass market margins due to price reductions in response to competitive pressures and the attendant lower margins on acquired and renewed customers. An 8% decline in mass market volumes sold, primarily due 0.6% monthly net

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TXU Residential Churn Accelerates

TXU Energy's residential customer churn accelerated in the quarter ending June 30, 2010, as TXU lost 19,000 residential customers versus March 31, 2010.

As of June 30, 2010, TXU's residential customer count was 1.830 million versus 1.849 million as of March 31, 2010 and 1.911 million as of June 30, 2009. The 19,000 net residential customers lost during the quarter represent an increase from the 13,000 lost in the first three months of 2010, and 14,000 lost in the final three months of 2009.

Attrition among TXU's small business (< 1 MW) customers slowed, as TXU reported 241,000 small business customers as of June 30, 2010, versus 250,000 as of March 31, 2010 and 279,000 as of June 30, 2009. The net loss of 9,000 small business customers compares favorably to the net loss of 12,000 customers during the first three months of the year, and 11,000 customers from September 30, 2009 to December 31, 2009.

TXU's large customer count as of June 30, 2010 was flat at 22,000 -- the same as reported as of March 31, 2010, and an increase versus the 21,000 reported a year ago.

Total customer count as of June 30, 2010 was 2.093 million, versus 2.121 million as of March 31, 2010 and 2.211 million as of June 30, 2009.

Retail electricity revenues (see chart) decreased $113 million, or 7%, to $1.476 billion and reflected the following:

- Lower average pricing decreased revenues by $141 million driven by the contract business market and also reflecting lower residential pricing. Lower average pricing in both business and residential markets is reflective of competitive activity and a change in customer mix.
- A 2% increase in sales volumes increased revenues by $28 million reflecting an increase in the business markets, partially offset by a decrease in the residential market. An 8% increase in business markets sales volumes reflected a change in customer mix and improved economic activity. A 3% decrease in residential sales volumes reflected a 4% decline in customer count that was driven by competitive activity.

Energy Future Holdings does not report Selling, General & Administrative expense at the retail level, but for its combined competitive units (retail and wholesale), SG&A expenses decreased $12 million, or 6%, to $180 million in the second quarter of 2010. Among other factors, the decrease reflected $15 million in lower transition costs associated with outsourced services and the retail customer information management system implemented in 2009, partially offset by $8 million in higher marketing expenses.

The competitive segment did not cite any incremental change in bad debt as part of its SG&A expenses for the second quarter versus the prior-year period. For the six months ending June 30, 2010, the competitive segment reported $15 million in increased bad debt expense for retail operations primarily associated with residential customers, reflecting higher delinquencies due to delays in final bills and disconnects resulting from a system conversion, customer losses and general economic conditions. All of this $15 million incremental bad debt occurred in the first quarter.

Energy Future Holdings' Competitive

TXU Data

Retail electricity sales volumes (GWh):

	Q2 '10	Q2 '09	% Change
Residential	6,848	7,084	(3.3)
Small business	1,993	1,908	4.5
Large business & other	3,925	3,551	10.5
Total	12,766	12,543	1.8

Average volume (kWh) per residential customer:

Q2 '10	Q2 '09	% Change
3,723	3,688	0.9

Retail electricity revenues *(millions):*

	Q2 '10	Q2 '09	% Change
Residential	$ 906	$ 984	(7.9)
Small business	263	295	(10.8)
Large business & other	307	310	(1.0)
Total	1,476	1,589	(7.1)

Electric Segment reported a net loss for the quarter of $427 million versus a loss of $78 million a year ago, reflecting higher interest expense and related charges, partially offset by higher realized net gains and lower unrealized net losses related to commodity hedging activities and higher baseload generation.

On a consolidated basis for the second quarter 2010, Energy Future Holdings reported a net loss of $426 million compared to a reported net loss of $155 million for the second quarter 2009. The second quarter 2010 reported net loss includes (all after tax) $93 million in unrealized commodity-related mark-to-market net losses largely related to positions in EFH's long-term hedging program and $165 million in unrealized mark-to-market net losses on interest rate swaps, partially offset by an $83 million debt extinguishment gain resulting from second quarter 2010 debt exchanges and repurchases.

Energy Future Holdings will hold an earnings conference call this morning.

Md. Procurement Group Discusses Change in Allegheny Residential Procurement Schedule

A report on the Maryland SOS procurement improvement process includes a potential transition plan for Allegheny Power's residential SOS procurement schedule to conform to the schedule used at the other Maryland utilities, though no recommendation is made concerning the schedule (Case 9064).

Allegheny's current residential procurement schedule provides for bidding in October 2010 and January 2011 for June 1, 2011 power flow (one 12-month and one 24-month contract for each procurement), and in April and June 2011 for June 1, 2012 power flow (one 12-month and one 24-month contract for each procurement).

Allegheny will not conduct Type I commercial SOS bidding in the 2010-11 bid cycle, because such load will be supplied through existing 2-year contracts. This schedule resulted from earlier agreements intended to accommodate the relatively small size of Allegheny's Type I load.

The report includes two alternatives for procuring Allegheny residential load.

Option One would continue the mix of one-year and two-year residential contracts with June 1 start dates for the time being, while leaving open the potential for future changes. Allegheny has used this mix for the last several procurement cycles in order to try and capture cost savings for customers by facilitating winning bidders' ability to select their own Auction Revenue Right paths and convert them into Financial Transmission Rights.

Option Two would transition Allegheny's procurement cycle to eventually bring it totally into step with the rolling two-year schedule for residential procurements used at the other utilities, with contract start dates of June 1 and October 1. The transition would be complete by June 2014.

Allegheny has serious concerns about Option Two, noting that ARR revenues are very significant for the Allegheny Zone. Allegheny believes that residential rates are appreciably lower when the bidding suppliers know that they will be able to control ARR path selection and FTR conversion if they win.

The procurement group report makes no recommendation on either option, but presents each for Commission consideration.

The procurement improvement group also agreed to establish a working group to examine alternatives to the current treatment of renewables in the SOS procurement process. Discussion has centered around treatment of renewable obligations if law or regulations change during the delivery period. A report shall be prepared for consideration in the 2011-12 procurement improvement process.

Md. Staff Issues Net Metering Working Group Report

Maryland PSC Staff have filed a working group report on net energy metering offering two alternate versions of amendments to the current regulations to conform to recent statutory changes (RM 41). Both proposals would ostensibly only govern the relationship between net metered customers and an "electric company," a term which does not include competitive suppliers.

The two alternatives represent different views of utilities and solar developers.

However, of interest to suppliers is the working group's discussion of settlement of net generation. One unidentified working group member argued that the proposed regulations will not ensure proper settlement of net generation and accounting of potential credits that result. The only competitive supply working group member was Washington Gas Energy Services.

Currently, settlement data appears to be transmitted with negative hours appearing as zero rather than the true negative value. This puts suppliers in the position of oversupplying in those hours. The problem is exacerbated at peak times, when solar distributed generation will be producing more power, since the over-supplied peak power costs more.

The unidentified working group participant suggested that the distribution company meter for the net customer's usage capture any hour when customer generation is greater than load as a negative value in the customer's consumption in that hour. At the end of each day, as the utility calculates the entire hourly load for a load serving entity (alternative supplier or SOS supplier), the total load requirement should net the negative hours for the customers that happen to have some net generation. Similarly, the hourly billing data for these customers that is delivered through EDI to the load serving entity should also reflect the negative values for the hours when there is any net generation.

The working group participant suggested that the following language should be added to the regulations:

"For commercial customers with interval metering equipment, the electric company shall use the net hourly energy consumed or produced to assign the energy requirement for the customer. The net energy metered each hour (positive or negative) shall be used for the PJM settlement process, even in cases when the total usage by the customer in a month exceeds the electricity generated by the customer."

This proposal was not included in either of the proposed versions of amendments included in Staff's report.

Briefly:

MP2 Energy Offering Residential Supply to Friends, Family

MP2 Energy has begun offering residential electricity in ERCOT to employees of certain commercial clients as well as friends and family.

MISO Updates CONE Value

The Midwest ISO and its Independent Market Monitor have petitioned FERC to raise the Cost of New Entry in its Module E resource adequacy mechanism from $90,000 per MW-month to $95,000 per MW-month effective June 1, 2011. The IMM's calculations resulted in a CONE of $95,730, but MISO and the IMM are proposing rounding the figure down for administrative convenience.

dPi Energy Offering AMI-based "Smart PrePay" Product

dPi Energy has launched a prepaid product which utilizes the usage data from provisioned advanced meters, with the product branded as "Smart PrePay." dPi said that the AMI-based product includes a flat rate of 12.9 cents with no monthly account fee, energy fee, or any other charges. An Electricity Facts Label for the product dated June 25 states that there is a $4.95 per payment transaction fee regardless of payment method. The dPi product includes standard features of AMI-based prepaid products including no credit check, no identification, no deposit, and daily or weekly usage and balance data available by cell phone or email. dPi's intent to offer a product using a customer premise prepayment device was first reported by *Matters* (Only in Matters, 6/29/10). PUCT Staff has a pending petition to revoke dPi's REP certificate (Only in Matters, 7/5/10).

FERC Seeks Additional Comment on Demand Response Compensation

FERC sought additional comment on its proposed rule to mandate that RTOs compensate demand response at the full LMP, specifically seeking feedback on cost allocation issues, and whether a net benefits test is required to determine the hours in which full LMP is paid. Among other questions, FERC asked that parties identify, in addition to the payments received from the wholesale market, any costs demand response providers and load serving entities incur, and whether these should be included for purposes of a net benefits test. FERC said that it will hold a technical conference on the proposed rule, with a date to be later announced (RM10-17).

Constellation Sells 14.5 MW Share in Geothermal Assets for $72.5 Million

Constellation Energy announced the sale of its 14.5 MW interest in the Mammoth Geothermal Plant near Mammoth Lakes, California to a subsidiary of Ormat Technologies, Inc. for $72.5 million (approximately $5,000/kW). Constellation Energy and Ormat shared a 50-50 interest in Mammoth-Pacific, L.P., which owns and operates the three geothermal plants comprising the 29 MW facility.

PECO Launches Final 2011 Procurement

PECO launched its final procurement for default service supplies for the period beginning January 1, 2011 (www.pecoprocurement.com). In the procurement, PECO will purchase full-requirements supply for residential and all categories of commercial and industrial customers as well as winter and summer peak, and one and two-year base load block energy supply for residential customers.

Maryland ... *from 1*

Allegheny is the only utility to interpret the PSC's order as excluding transmission charges as part of the SOS Supply Price Comparison Information.

BGE's price comparison information includes the transmission rate, and also includes the actual bypassable Rider 8 (Energy Cost Adjustment) for the SOS price listed for period ending September 30, 2010. However, the October 1, 2010 through May 31, 2011 SOS rate in the bill message excludes Rider 8 as no projection of the rider is determined for this period.

Pepco and Delmarva also include the transmission rate in their SOS pricing comparison, but apparently do not include the bypassable Procurement Cost Adjustment.

Allegheny also interpreted the PSC's order as only requiring the bill message on residential bills. BGE and the Pepco utilities have interpreted the order as requiring the bill message for any customer class whose bill previously included Price to Compare information, which includes Type I customers.

BGE reported to the PSC that it will be including on its website an optional, user-friendly supply price calculator, whereby the customer can determine their individual, projected SOS supply cost based on their actual energy usage, and compare that cost to offers from other licensed suppliers. BGE will also provide on its website a more direct link to the newly designated Supply Price Comparison Information so that customers will no longer be required to "drill down" through the site to access this information.

BGE also proposed, in addition to a redesign of its website, to provide each customer with the ability to see a Usage Profile for the immediately preceding 12 months. Information to be provided will include the average temperature for each month, the type of reading for each month, the kWh or therms, as applicable, for that month, and the days of service for each of those 12 months. Once the initial start-up costs are expended, this additional information will be essentially available to all customers at no charge.

With such usage information provided online, BGE did not recommend including 12 months usage with actual kWh figures on monthly bills, as the provision of such information would increase printing and postage costs by approximately $550,000 annually by making the BGE bill two pages, in addition to start-up costs to implement the changes.

At Delmarva, providing 12-month usage data on bills would cost $200,000 to $300,000. Pepco already provides 12-month usage data on bills.

Allegheny provides a bar graph of 12-month usage on bills but not actual kWh totals. Allegheny said including actual kWh totals would cost $100,000.

Reliant ... *from 1*

attrition between July 2009 and June 2010, also contributed to lower gross margin.

Reliant President Jason Few reported that Commercial and Industrial margins on new business signed in the second quarter were higher sequentially versus the first quarter of 2010.

Reliant's customer count as of June 30, 2010 stood at 1.55 million customers, versus 1.58 million as of March 31, 2010 and 1.66 million as of June 30, 2009.

Mass market customer count as of June 30, 2010 stood at 1.488 million customers, versus 1.520 million as of March 31, 2010 and 1.589 million as of June 30, 2009.

Commercial and Industrial customer count as of June 30, 2010 was 63,000 versus 64,000 as of March 31, 2010 and 68,000 as of June 30, 2009. Reliant said that renewal rates of Commercial and Industrial customers improved during the second quarter of 2010, but not enough to totally stem attrition.

Reliant reported that it continues to see improved payment patterns among its customers. Bad debt expense totaled $22 million for the first half of 2010, or 0.9% of retail customer revenues.

Parent NRG Energy raised Reliant's guidance for full-year adjusted EBITDA to $650-$700 million from the previous forecast of $500 million.

NRG Wholesale

Net income for NRG's Texas fleet was $157 million for the second quarter, versus $98 million a year ago. The Texas fleet's adjusted EBITDA, excluding mark-to-market, was relatively steady at $343 million versus $346 million a year ago. The Texas economic gross margin increased $12 million from the combination of slightly higher hedged volumes and prices, plus an increase in ancillary services provided to Reliant Energy. These gains were offset by lower generation and higher maintenance costs relating to a refueling outage at the South Texas Project.

Due to the uncertain timing of any potential federal load guarantee for the expansion of the South Texas Project, NRG has reduced monthly spend on the new nuclear project by 95% to $1.5 million per month.

The quarterly net loss for NRG's Northeast fleet was $2 million, versus net income of $42 million a year ago. Adjusted EBITDA, excluding mark-to-market, for the second quarter was $101 million, a decrease of $16 million from the second quarter of 2009. Net energy margins

Reliant Data

(in millions except where noted)	Three months ended June 30, 2010	One month ended April 30, 2010	Two months ended June 30, 2010	Two months ended June 30, 2009	% Change vs. Comparable Period
Operating Revenues					
Mass	$ 808	$ 190	$ 618	$ 761	(19)%
Commercial & Industrial	502	151	351	437	(20)
Supply management	31	13	18	52	(65)
Contract amortization	(59)	(22)	(37)	(75)	51
Total	1,282	332	950	1,175	(19)
Total Retail Gross Margin	308	74	234	320	(27)
Electricity sales volume — GWh					
Mass	5,732	1,275	4,457	4,851	(8)
Commercial & Industrial	6,683	2,059	4,624	5,580	(17)

were unfavorable $34 million due to lower hedged prices.

Consolidated net income at NRG across all business units was $210 million versus $432 million a year ago. Consolidated adjusted EBITDA, excluding mark-to-market, was $693 million versus $747 million a year ago.

During an earnings call NRG CEO David Crane said that the current environment is an "attractive" market for asset buyers, and believes that this market dynamic is going to persist for at least a while longer. NRG has not appreciably expanded its conventional portfolio through acquisition, though it has purchased several renewable projects.