Energy Choice Matters

January 28, 2010

RESA Petitions N.Y. PSC to Prevent Drops to Bundled Service due to Account Number Changes

The Retail Energy Supply Association petitioned the New York PSC to amend the Uniform Business Practices to (1) prohibit utilities from returning a customer to full utility service unless such a request to return to full utility service has been made by the customer or the ESCO acting on behalf of the customer, and (2) allow ESCOs to retain a customer that has previously either requested or was scheduled to return to full utility service upon customer consent to remain with the ESCO (98-M-1343).

RESA said that a utility should only be allowed to effect a customer return to bundled service under the terms of UBP Section 5.H.1. RESA noted that when a customer experiences a name change or other data modification that precipitates a utility account number change under the utility's record keeping system, the ESCO will be dropped from the account automatically, without notice to the ESCO or customer. "Under this process, the termination of ESCO service will occur even if the customer has not expressed any interest or desire to return to utility commodity service," RESA said.

This practice, RESA suggested, "violates the Uniform Business Practices ('UBPs'), conflicts with the legal obligations of the utility to act in a just and reasonable manner to the customer and the ESCO, and creates a tortious interference by the utility with the ongoing contractual relationship between the ESCO and the customer."

RESA stressed that per the UBP, a customer may return to bundled service, "by contacting either the ESCO or the distribution utility." Neither occurs under the automatic process prompted by a change in account number.

RESA further noted that Section 5.K.1 of the UBP states that a, "change of a customer to another provider without the customer's authorization ... is not permitted."

"A return to full utility service by an ESCO customer must be preceded by the customer first expressing the desire to terminate ESCO service and return to the utility. Absent satisfaction of this UBP codified precondition, the utility has no authorization to effectuate a change in providers or

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UGI Energy Services Net Income Up 50% on Higher Margin

Total margin at UGI Energy Services for the quarter ending December 31, 2009 (first fiscal quarter of 2010) increased to $41.0 million, up from $32.4 million a year ago, on higher volumes and unit margins in its retail gas and electric marketing businesses. Net income for the Energy Services unit for the quarter was up at $16.4 million, versus $10.7 million a year ago.

UGI said that it saw a "significant increase" in natural gas marketing margin resulting from 5% higher volumes sold and higher unit margins. Updating investors on its small commercial customer acquisition plan, UGI said that Energy Services has signed 6,000 small commercial gas customers since the start of fiscal 2009, and has seen "great success" in retaining accounts when up for renewal. Small commercial gas customer growth since September 30, 2009, was about 500 customers.

Although retail electric marketing is "still fairly small," executives said that activity has ramped up considerably, particularly with an increased focus in Pennsylvania in the PPL territory, and in

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Maine PUC Approves CMP, BHE Standard Offer Rates

The Maine PUC approved Standard Offer rates for the Central Maine Power and Bangor Hydro-Electric medium and large non-residential classes for the period beginning March 1, 2010.

CMP Medium Commercial Class ($/kWh)

Mar-10	$0.07003
Apr-10	$0.06853
May-10	$0.06653
Jun-10	$0.06703
Jul-10	$0.07203
Aug-10	$0.07403

CMP Large Commercial Class ($/kWh)

Mar-10	$0.07771
Apr-10	$0.07407
May-10	$0.07265
Jun-10	$0.06960
Jul-10	$0.07897
Aug-10	$0.07788

BHE Medium Commercial Class ($/kWh)

Mar-10	$0.0670200
Apr-10	$0.0660200
May-10	$0.0640200
Jun-10	$0.0650200
Jul-10	$0.0690200
Aug-10	$0.0690200

BHE Large Commercial Class ($/kWh)

Mar-10	$0.0790000
Apr-10	$0.0740000
May-10	$0.0660000
Jun-10	$0.0650000
Jul-10	$0.0690000
Aug-10	$0.0690000

Calif. ALJ Would Reject Nonbypassable Charge for PG&E Solar Program

A California PUC ALJ's proposed decision, as well as a Commissioner's alternate, would both deny Pacific Gas & Electric's petition to collect any potential stranded costs from its solar photovoltaic program via a nonbypassable charge. Both draft decisions would institute a 500 MW solar photovoltaic program at PG&E including 250 MW of utility-owned generation, and 250 MW of merchant generation procured via competitive solicitations (A. 09-02-019, Matters, 2/25/09).

The cost of the solar photovoltaic program should not be allocated to direct access customers, as requested by PG&E, because, "[r]equiring direct access customers to incur [the] cost of the PV Program would be unreasonable and represent double payment," the ALJ found.

The solar photovoltaic program, "provides generation exclusively for the benefit of PG&E's bundled customers," and does not benefit direct access customers, the ALJ noted. "Moreover ... direct access providers are required to establish their own RPS programs, and direct access customers bear all the responsibility for costs under those programs. Since PG&E's PV Program is designed to help PG&E meet its own RPS obligation, there is no RPS-related benefits to direct access customers," the ALJ added. An alternate proposed decision from PUC President Michael Peevey made the same findings with respect to the nonbypassable charge.

Both proposed decisions would establish a 500 MW solar photovoltaic program with 250 MW of utility-owned generation and 250 MW of merchant generation.

Both drafts would reject, however, PG&E's proposal to price both the merchant and utility-owned generation at a fixed price, based on PG&E's expected levelized cost of energy for the utility-owned generation portion of the PV program, which equates to a pre-Time-of-Delivery price of $246/MWh.

The fixed price proposed by PG&E results from several assumptions, but the ALJ has, "little confidence they represent accurate information at this point, much less going forward." Various factors impact project economics, including location, equipment prices, labor costs, and transmission costs, the ALJ said, in rejecting a uniform price.

"[G]iven the record evidence regarding the rapidly changing market for solar PV, and the reasonable concerns expressed about cost, we do not believe it is reasonable for the Commission to adopt an administratively set capital cost and price for purposes of either the

UOG or the PPA component of the PV Program," the ALJ found.

"These project-specific attributes and associated costs are best sorted out via a competitive process where each project specific circumstance is considered in developing its bid," the ALJ said, proposing that a competitive solicitation would be used to price PPAs with the merchant assets. The revenue requirement for the utility-owned generation portion of the PV program would be based on the weighted average price per kilowatt-hour received in the PPA solicitations combined with the actual annual production for each utility-owned facility.

The ALJ's draft would direct PG&E to solicit 50 MW of merchant solar, to be signed to 20-year PPAs, annually for five years. The ALJ rejected calls to front-load the procurements.

The ALJ's draft and Peevey's draft differ in the size of projects eligible for the solar photovoltaic program. The ALJ would allow PG&E to install utility-owned solar projects from 1 MW to 20 MW in size, while limiting merchant projects to 3 MW to 20 MW in size. Peevey's decision would expand the eligible merchant projects to those which are 1 MW to 20 MW in size. Peevey's alternate would also allow up to 5% of the utility-owned generation capacity to be from facilities less than 1 MW in size and/or roof-mounted. The ALJ draft would not allow these types of projects to be pursued under the program.

EIA Data Underestimates Price Decreases in Texas Competitive Market

Data from the Energy Information Administration, often cited in criticisms of electric restructuring, "significantly understates the drop in Texas residential prices under competition," a paper from the Texas Public Policy Foundation found.

"[A]n examination of actual residential market prices shows that the EIA data make poor proxies for prices in Texas' competitive markets," said Bill Peacock, Director of the Foundation's Center for Economic Freedom. Peacock reported that the average offer by REPs in competitive regions of Texas in December 2009 was 11.01 cents/kWh, while consumers could choose offers as low as 8.52 cents/kWh. However, the EIA reported that Texas consumers paid an average of 12.26 cents/kWh in October 2009 (which is the most recent EIA data).

For 2009, EIA data still shows Texas above average nationally, but average Texas competitive prices are actually below the national average, Peacock added.

Peacock further noted that EIA data shows Texas' 2001 prices as slightly above the national average, even though regulated prices in ERCOT prior to competition were significantly higher. "Because of this, relying on EIA price data significantly understates the drop in Texas residential prices under competition," Peacock said.

For instance, 2001 regulated rates in Texas' competitive areas (9.98 cents/kWh) averaged 15.8 percent above the national average. Today, however, the average competitive price (11.01 cents/kWh) is 8.71 per cent below the national average, while the average of the 15 lowest offers (9.27 cents/kWh) is 23.13 percent below the national average, Peacock said.

The blending of competitive and non-competitive regions by the EIA accounts for some of the difference in the comparisons, Peacock noted. Additionally, small and new REPs may not report sales data to the EIA because the EIA is unaware of such load serving entities, giving an incomplete picture of pricing.

Competitive prices in Texas have fallen not only relative to national prices, but are, on average, lower in real terms than the 2001 regulated prices in Texas, Peacock added. Adjusted for inflation, the average competitive price today is 9.46 percent below the average 2001 regulated price. The average of the 15 lowest prices is 24.39 percent lower, and the lowest average price is 30.5 percent lower. "Even without adjusting for inflation, however, most Texans can easily buy electricity today below 2001 regulated prices," Peacock said.

Texas' competitive rates also compare favorably with several neighboring states, Peacock added. The average price of the 15 lowest offers in Texas is lower than the average price in New Mexico, Oklahoma, and Arkansas, and the average lowest price is close to the average price even in low-cost Louisiana, Peacock said (see chart). Further, Texas prices are lower -- significantly in many cases -- than the average price in the other four of the five largest states, such as New York (19.17 cents/kWh) and California (14.08 cents/kWh).

"Perhaps the lower price of electricity in Texas is one reason it has recently moved past New York and California as the home to the most Fortune 500 companies," Peacock said.

Peacock's report also made note of ERCOT's robust reserve margins under restructuring, which Peacock called a, "direct result of its competitive energy-only market."

"Though the electricity market structure still does not transmit signals perfectly, the energy-only market has operated well enough to provide Texas with ample reserve margins while shifting the risks of over-construction from consumers to investors," Peacock added.

Average Residential Rates (¢/kWh)

New York	19.17
California	14.08
Florida	12.31
U.S. Avg.	11.76
Illinois	11.42
TX Avg. Offer	11.01
New Mexico	10.41
Oklahoma	10.35
Arkansas	9.72
TX Avg. Lowest 15	9.27
TX Avg. Lowest	8.52
Louisiana	8.17

As reported by TPPF

Mich. Prepared to Take Action on Transmission Cost Allocation as Part of Wind Zone Designation

The Michigan PSC designated all or portions of the counties of Huron, Bay, Saginaw, Sanilac and Tuscola (known as Region 4) as the "primary" wind energy resource zone per Act 295, in an order issued yesterday (U-15899).

The Commission also said that Allegan county (Region 1) shall be designated as a wind energy resource zone due to potential necessary transmission upgrades and the likelihood for project development in that region.

The two designated zones are eligible for expedited transmission siting treatment as provided by Act 295. As for Regions 2 and 3, the Commission noted that there are no currently planned projects in those locations, and that the Wind Energy Resource Zone Board determined that there was little interest in developing wind farms in either area.

The PSC said that the maximum estimated wind capacity of Region 4 is 4,236 MW. About 70% of Michigan's estimated renewable energy generation is located in Region 4. The maximum estimated wind capacity of Region 1 is 445 MW.

The PSC noted that it must address the issue of cost allocation for the transmission build-out required to develop renewable wind generation in Region 4. Currently, per the MISO tariff, all costs of transmission to serve these wind projects would be recovered from retail customers in that transmission owner's local geographic territory, which, in Michigan, corresponds with the distribution utility's local pricing zone. Region 4 falls entirely within the service territory of Detroit Edison and Thumb Electric Cooperative. "Detroit Edison is rightly concerned that its customers may end up paying the costs for all of the anticipated transmission upgrades in addition to the cost of related investments Detroit Edison must make to upgrade its high voltage distribution circuits and substations to accommodate electric power flows that will result from the construction of the higher voltage transmission lines in this area. This is despite the fact that other utilities within Michigan will be utilizing that same transmission to meet their renewable energy plan requirements," the Commission said.

"The Commission believes one way to solve this problem is an agreement between the parties on cost sharing or allocation. This agreement would be to aggregate and allocate among the parties the costs of building the needed transmission to support development of the Region 4 wind resources," the PSC said, noting that parties may enter into agreements to depart from the default MISO cost allocation.

Toward that end, the Commission ordered that all affected parties shall have 21 days to reach an agreement on a voluntary cost allocation methodology for the transmission upgrade projects needed to develop wind generation in Region 4.

If after the passage of 21 days, the parties are unable to resolve a cost allocation treatment amongst themselves, the Commission said that it will pursue another process to resolve the matter from amongst the available options that are open to the Commission. "Among the options available is the creation of a single pricing area in Michigan's Lower Peninsula for transmission charges," the PSC said.

Briefly:

DPUC Approves CL&P Procurements

The Connecticut DPUC approved Connecticut Light & Power's recent procurements for Last Resort Service supplies for the three-month period beginning April 1, and Standard Service supplies for a portion of 2010, 2011 and 2012. Updated Last Resort Service rates must be posted by February 16. As the DPUC has already approved retail rates for Standard Service for the entirety of 2010, rates will not change on July 1, the DPUC said. Prior to the recent procurement, CL&P had already procured 100% of Standard Service supplies for the first half of 2010, and 90% of Standard Service supplies for the second half of 2010.

Constellation NewEnergy Names Michael Smith to Lead Renewable Products

Constellation NewEnergy has named Michael D. Smith as senior vice president of retail green initiatives to oversee the development and implementation of sustainable product offerings, including renewable generation, energy efficiency, demand response and carbon reduction strategies. Smith will also lead the company's growing solar power business and a dedicated commercial solar sales team focused on deployment of customer-sited solar installations. Smith has been with Constellation Energy since 2003, and previously served as vice president and director of Constellation Energy's international energy policy office in London, where he managed Constellation's activities in the European Union carbon and renewable energy markets.

ERCOT Reports Disclosure of Adjusted Metered Load

ERCOT filed a Notice of Protocol Violation with the PUCT associated with the disclosure of Adjusted Metered Load (AML). On Operating Days November 21, 2009 through January 8, 2010, ERCOT said that it inadvertently included a data record labeled "POSTEDAML" in the Client Data Reports (CDRs) posted for downloading on a secure web portal folder specific to the Qualified Scheduling Entity (QSE) that owns the data. The POSTEDAML data is a Nodal data record developed to support Nodal Protocol Section 1.3.3, Expiration of Confidentiality, and was not intended to be released to any Market Participant at this time. The CDRs which included the POSTEDAML data provided AML data for Load Serving Entities (LSEs) not represented by that QSE. Because the error inadvertently disclosed AML data identifiable to a specific LSE, ERCOT considers the data included in POSTEDAML to be Protected Information for up to 365 days after the applicable Operating Day. ERCOT said that it removed all affected files and reposted corrected CDRs. ERCOT also corrected the computer code to ensure that the POSTEDAML Nodal data record will not be included in future CDRs.

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transfer the customer to utility service," RESA said.

RESA further noted that UBP Section 5.H.1 does not explicitly provide for the customer or the ESCO acting on behalf of the customer to rescind a requested return to full utility service in cases where the customer desires to remain with their current ESCO.

RESA suggested adding language to the relevant UBP section stating that, "In the event the distribution utility receives notice from the incumbent ESCO or the customer, no later than three business days before the effective date of the scheduled return to full utility service, to cancel a previous request or scheduled return to the utility, the distribution utility shall cancel the request and maintain service with the incumbent ESCO."

"This approach is eminently reasonable and equitable to all parties," RESA said, noting that, in many cases, a customer, after speaking with their ESCO, decides that their prior decision to return to full utility service should be modified. RESA noted that customers may not be aware of potential liability (e.g. early termination fees) associated with returning to bundled service until speaking with their ESCO.

ESCOs would have to obtain the customer's assent in accordance with the methods allowed under the UBP to rescind a requested drop to bundled service, RESA said.

RESA likened its proposal to the recently approved ESCO contest period, which grants the incumbent ESCO the ability to stop a previously scheduled switch to another ESCO (but not a drop to bundled service) after obtaining consent from the customer.

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preparation for the removal of rate caps at the remaining utilities at the start of 2011. Retail electric volumes were up 40% versus the year-ago period, UGI said.

Energy Services also saw higher margin from an increase in electric generation margin (on a 16% increase in sales and higher average unit margins), and stronger peaking and asset management margins. Earnings were also lifted by lower generation maintenance costs.

Operating income for Energy Services was higher at $27.7 million versus $18.2 million in the prior-year quarter. Revenue for the quarter was $312.3 million, versus $359.1 million a year ago.

UGI has not yet filed a 10-Q.