Energy Choice Matters

*May 7, 2008*

# Michigan PSC Staff to Recommend UG&E License Revocation If AGS Doesn't Suspend Marketing

The Michigan PSC Staff is preparing a filing that recommends the revocation of Universal Gas and Electric's alternative gas supplier license unless UG&E agrees to suspend its marketing efforts while it corrects alleged tariff violations and other staff concerns, Staff reported to the Commission (U-15509).

The Staff believes UG&E has been unresponsive in adopting needed customer service remedies, and the "deterioration of the situation" prompted Staff's notice, which Staff considers a final attempt to encourage UG&E to fully address Staff's concerns.

Staff intends to file its license revocation petition on May 30 unless UG&E agrees to suspend marketing. Staff has, "found many of Universal's responses shallow, evasive and, in some instances, misleading," referring to UG&E's monthly reports on its marketing practices.

In particular, Staff attacked UG&E's position regarding when notification letters of a supplier switch have to be sent to customers. The tariff mandates such letters to be sent out seven days after customers enter an agreement, but UG&E argued that customers signing an enrollment form are not entering an agreement with UG&E, and thus the clock does not start at that point (Matters, 5/1/08).

"The company's response to this significant component of the investigation was another masterful attempt to spin the data and falsely interpret the tariffs to conform to their liking," Staff claimed.

Separately, Staff requested that the Commission commence a formal complaint proceeding against UG&E for unauthorized customer switching, based on the alleged failure to timely send enrollment confirmation letters to customers (U-15577). UG&E has argued under its interpretation of the tariff it has met the deadline for sending such confirmation letters.

Calling the allegations a, "particularly glaring violation of the switching process," Staff has documented, based on UG&E's reports to Staff, over 2,000 cases where customers did not receive a confirmation letter within seven days of enrolling. Staff expects over 45,000 violations to be

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# Duke Ohio EDC Won't Pursue Market-Based Rates in First Post-RSP Filing

Duke Energy Ohio does not intend to request approval for market-based rates in its initial filing with PUCO under the state's new electricity law, Duke told PUCO Chairman Alan Schriber in a letter meant to allay concerns about Duke's proposed transfer of Ohio generation assets (Matters, 4/30/08).

Duke will file only for approval of an electric security plan, a cost- and negotiated-rate successor to the rate stabilization plans, Duke reported.

Duke assured PUCO that it does not intend to transfer its assets from Duke Energy Ohio without PUCO approval as required by law. Schriber had raised concerns that Duke's application at FERC to transfer 22 plants from Duke Energy Ohio into new LLCs seemed "suspect" and potentially designed to circumvent Ohio's new law.

Duke stressed that it has been contemplating the asset transfers for some time (dating back to early restructuring) but delayed such separation due to its rate stabilization plan. It then waited for the Ohio legislative session to shake out to ensure its filing reflected subsequent legislation.

Five of the plants to be transferred were competitive units from Duke Energy North America that were brought into the Duke Energy Ohio fold as part of the Cinergy merger, but have not been subject to PUCO regulation, and have not been part of Duke's rate stabilization plans. Duke does not see a reason why PUCO would be concerned with the transfer of those plants.

## PSEG Doubts N.J. Power Authority Will Be Created

PSEG CEO Ralph Izzo doesn't think there is a "high probability" of any state power authority taking form in New Jersey, he told analysts on an earnings call.

The potential for a state power authority, which could possibly build new generation, has been "significantly downplayed" in the latest draft of the state's energy master plan, Izzo reported. He sees an increased emphasis on using existing state agencies to meet climate and environmental goals, rather than creating a new entity, based on conversations with policymakers.

Policymakers are trying to steer clear of adding to the state's budget by creating a new agency, Izzo explained, and sees a greater probability that the BPU and the state's Economic Development Authority and Department of Environmental Protection will work together on energy efficiency through existing programs or low-interest loans.

PSEG Power has bid new peaking capacity into the RPM auction and will make a decision on going forward with new build based on the auction results. PSEG had previously announced plans for 300-400 MW of peakers in New Jersey but would not disclose how many units it had bid into RPM in the current auction.

Strong results at PSEG Power helped its parent post a 36% jump in profits, with the parent’s quarterly earnings rising to $448 million versus $329 million a year ago.

PSEG Power operating income rose to $275 million from $219 million in the year-ago quarter on solid operations, re-contracting at higher prices and the RPM capacity market.

## BGE Asks for More Time For Re-Regulation Comments

Baltimore Gas & Electric asked the Maryland PSC to extend a May 8 deadline to provide comments on Part I of the PSC's interim report on re-regulation released in December of last year.

The PSC only posted a notice seeking comments on the report April 30 (PC 13), which gave stakeholders only five business days to develop thoughtful comments on a report totaling some 280 pages, BGE noted. A hearing is set for May 14. Some parties submitted unsolicited comments to the PSC's report in December.

The outcome of the Commission's review of issues in the report, "could lead to sweeping changes in Maryland's electric market," BGE pointed out, adding that, "the Commission should be well aware that such sweeping changes can have unintended outcomes" unless stakeholders take the time to fully analyze possible changes.

The comment and hearing dates are just prior to the release date (May 16) for results of the RPM Base Residual Auction, BGE observed, which is an important milepost in the current review of Maryland's market. BGE suggested that stakeholders be given two weeks to review the results of the auction so they can provide more valuable comments on the PSC interim report. BGE proposed a May 30 comment date.

## PJM Explains Reserves Market Won't Increase Peaking Generation Dispatch

PJM's proposal to establish a market-based mechanism, known as the Day-Ahead Scheduled Reserves (DASR) market, to procure supplemental reserves won't increase the peaking units committed in the market, the RTO told FERC in answering a concern raised by the Maryland PSC (ER08-780).

The PSC had reasoned that the DASR market would commit less intermediate generation to day-ahead operating reserves, leaving the gap to be filled by more expensive quick-start generation (Matters, 4/22/08).

But the DASR market will simply not change PJM's day-ahead reserve commitment philosophy or methodology, PJM replied.

DASR only changes the means of procuring and compensating those reserves, through a competitive auction with a single clearing price, rather than through inefficient out-of-market payments, PJM explained.

The DASR market will, if anything, tend to reduce PJM's reliance on peakers for operating reserves for two reasons, the RTO added.

First, the DASR market opens reserves to competition from demand resources for the first time, providing an opportunity for load resources to displace the most expensive generation.

Second, the DASR market will procure most of the region's needed reserves through a co-optimization that minimizes total production costs (i.e., both energy and reserves), giving baseload and intermediate generation greater opportunity to provide reserves than under today's rules, PJM noted.

## Heat Rate Change in DALRP Price to Boost DR Dispatch

FERC should quickly approve changing the "egregiously high" heat rate index utilized in ISO New England's Day Ahead Load Response Program (DALRP) as proposed by the ISO, EnerNOC urged. (ER08-830).

But EnerNOC also argued FERC should direct the ISO to immediately convene a stakeholder process to address creating a methodology to ensure accurately calculated customer baselines, and prevent artificial restrictions on demand response's participation in energy markets.

The ISO has proposed lowering the DALRP reference heat rate upon which the DALRP minimum offer price is based from 12.92 to 11.37 MMBtu/MWh. The change is in response to the ISO's recent update of the fuel price used to calculate its minimum offer price, which results in DALRP resources being called less often (Matters, 4/7/08). Lowering the heat rate will in turn lower the minimum offer price and incrementally increase the opportunity for demand resources to be called, EnerNOC noted. For April, the DALRP hours which clear the minimum price would have increased from 11% to 21% under the new heat rate.

While the change would be an improvement, the ISO still needs to eliminate barriers to demand response's participation in energy markets by developing a customer baseline methodology that accounts directly for seasonal shifts in customer load and for scheduled demand changes such as vacations, maintenance outages, and plant shutdowns, EnerNOC argued.

## EPSA Questions SPP Exemption from Conditional Firm Service

An exemption from offering Conditional Firm transmission service under FERC Order 890 granted to RTOs does not apply to SPP, EPSA argued, because customers in SPP are unable to buy through transmission congestion (OA08-104).

While SPP does offer a real-time energy imbalance market that does allow customers to buy through transmission congestion, the imbalance market is only 8% of the total load of SPP, EPSA noted.

SPP is primarily a bilateral market where energy sales rely on prior reservation of firm transmission, EPSA reported.

The exemption from conditional firm service under Orders 890 and 890-A apply to RTOs that operate a market that accepts all transmission schedules and manages congestion through the use of Locational Marginal Pricing (LMP), EPSA claimed, which SPP does not use.

SPP's market is also not analogous to other RTO markets, EPSA added, because SPP does not offer financial transmission rights as a way for new developers or existing generation to access transmission capacity and pay their way through congestion.

SPP's energy imbalance market is currently the only congestion resolution mechanism, EPSA observed.

The lack of a Conditional Firm product in SPP maintains a barrier to new and existing market entrants in the SPP service territory and limits SPP's ability to make the most efficient use of its existing transmission capacity, EPSA reasoned.

## Bates White Analysis Sees Risk, Little Upside to AF&PA Capacity Market Fix

The Financial Performance Obligation mechanism for capacity markets suggested by the American Forest & Paper Association (Matters, 4/4/08) would likely create a less reliable electric system due to perverse incentives for generators, economists from Bates White concluded in an analysis.

The financial performance obligations require generators receiving capacity payments to financially guarantee the delivery of energy to the real-time energy market at or below a prespecified and regulator-determined price, according to Bates White.

LSEs receive a financial hedge for their real-time energy purchases while a financial obligation and additional price risks are imposed on generators, Bates White noted.

The financial performance obligation design does not incorporate any direct compensation for the proposed long-term energy contracts (and the risk) embedded with the capacity obligation. Such a design, Bates White cautioned, would prompt generators to delist (or export) their capacity resources, especially in high-LMP areas where new capacity is needed most, if their capacity supply bids can not adequately incorporate the additional risks.

That outcome will increase the cost of financial hedging and thus raise costs in the short run while reducing economic incentives for new generation and demand response, Bates White claimed.

Such "skeletal" proposals that would turn capacity markets upside down will only hinder investment by creating more uncertainty, EPSA argued in commenting on the report.

## *Briefly:*

**BGE Demand Response Incentives Unchanged; Cost Recovery Accelerated**

Baltimore Gas & Electric will be allowed to recover the costs of its demand response program a year earlier but won't be allowed to alter the incentive structure at this time, the Maryland PSC ruled in a letter order released yesterday (Matters, 4/30/08). BGE will be allowed to implement the cost recovery surcharge effective January 1, 2009 instead of 2010 since that will ultimately lessen program costs for ratepayers by reducing the carrying costs associated with deferring cost recovery. The PSC declined to adjust the incentive structure because BGE did not support its new method of calculating incentives (to account for the fact the Southwest MAAC Variable Resource Requirement curve didn't clear the RPM auction) would provide the same present net value incentive amount as the current incentive structure. BGE also did not provide documentation that the new incentive structure would have no adverse affect on ratepayers, the PSC noted.

**Maine PUC Asks About Smart Meters, Appropriate SOS Pricing**

The Maine PUC issued a list of questions to suppliers regarding advanced metering (2006-661, 2005-554). The Commission wants to hear of potential market savings from advanced meters and preferred program designs. The PUC is particularly interested in drawing on the experience of suppliers offering real-time or other innovative products to larger customers, and is seeking suggestions on how such products can be offered to smaller customers. The PUC asked what supply programs and pricing structures are "best suited" for each customer class: residential, commercial and industrial. The Commission wants to know if more than one program or pricing mechanism should be available under SOS, and what complications arise if multiple products are offered under SOS. The questions also deal with the impact of lagged ICAP tags on demand response, and the appropriate intervals for pricing and settlement. Comments are due May 30.

**Md. PSC Ponders Additional Solar REC Programs**

Since the solar industry may desire a broader range of services than simple registration and tracking of solar RECs, the Maryland PSC asked stakeholders to comment on what additional services solar REC generators, LSEs, installers and customers might desire, and how to fund such services (PC11 and RM32). Some stakeholders have suggested that the Commission implement training sessions for new and existing generators; creation of a regional bulletin; creation of a price reporting system; annual audits of solar generation systems; an automated production tracking system; and provision of a customer service hotline to respond to solar REC inquiries. Funding for these services has not been provided to the Commission, whose rules contemplate funding only a registration and tracking system. Comments are due May 30.

**Shell Seeking to Serve Larger Illinois Customers**

Shell Energy North America is seeking to serve Illinois electric customers with annual usage above 15,000 kWh in all IOU service territories, according to its ARES application which was publicly posted yesterday (Matters, 5/6/08). Shell is not seeking single billing authority.

**FERC OKs Dynegy Market-Based Ancillaries Sale**

FERC granted Dynegy's request to sell ancillary services to Ameren at market-based rates, by granting a waiver of a tariff prohibition on sales of ancillary services at market-based rates by a third-party supplier to a public utility that is purchasing ancillary services to satisfy its OATT requirements to offer ancillary services to its own customers (ER08-356). However, FERC subjected the approval to any decision the Commission makes in a pending rehearing request in ER07-323, which involves similar market-based ancillary service sales. The market power concerns raised by Constellation in the docket (Matters, 2/13/08) will be addressed in ER07-323, FERC said. Ameren's 2007 RFP was a reasonable and appropriate method to solicit potential ancillary service suppliers for an interim period until the Midwest ISO ancillary services market becomes operational, FERC noted.

**Tougher Midwest ISO Credit Rules for FTR Bidding Approved**

FERC approved revised bid credit requirements for financial transmission rights in the Midwest ISO market, proposed in Part I of an application by MISO (ER08-622). The Commission will address in a future order MISO's proposed Part II hold credit requirements, since MISO had requested expedited action of the Part I bid requirements. MISO's bid credit requirements, meant as an interim measure until stakeholders create a more robust policy, will better protect MISO customers from default than the existing credit policy, FERC observed. MISO will apply a minimum bid requirement to buy negative FTRs, as well as bids to purchase zero and low-priced FTRs.

**Revenues Higher at Suez**

Suez's North American energy operations boosted quarterly revenues by EUR 73 million, mainly due to the commercial successes of Suez Energy Resources North America plus progress in the merchant power plant business.

**Beacon Wants Deadline for ISO-NE Market Rule 1 Change**

ISO New England needs to rewrite Market Rule 1 to be in compliance with FERC's Order 890 which calls for regulation markets to be opened to non-generation sources, Beacon Power told FERC (ER08-832). Although the ISO's OATT permits non-generation resources to provide regulation services, Market Rule 1 still limits regulation services to generation. The ISO is in the process of modifying Market Rule 1 to ensure non-discriminatory access to the regulation market, but Beacon asked FERC to order that such changes be completed by May 2010. That's the end date for a pilot program reviewing non-generation sources of regulation services (such as storage technologies), and Beacon wants to make sure such technologies can participate in the regulation market upon completion of the pilot. It is "unreasonable" for non-generation resources to assume the risk of millions of dollars invested in a pilot program without the assurance that those technologies will be allowed to compete in the market at the end of the pilot, Beacon argued.

**Suez, PUCT Staff Agree on LaaRs Penalties**

Suez Energy Marketing NA and the PUCT staff have filed a settlement for Commission approval regarding Suez's failure to adhere to ERCOT Protocols § 6.5.4(2) concerning Load acting as Resource (LaaR) service requirements (35650). Suez would pay $73,375 in administrative penalties under the pact, which resolves two instances in 2006 and 2007 where Suez, as a QSE for LaaRs, failed to deploy 95% of its scheduled LaaRs within 10 minutes of ERCOT instruction.

**DPUC Appeals Another FERC ICR Order**

The Connecticut DPUC has appealed FERC's decision on ISO New England's installed capacity requirement in ER05-715 to the U.S. Court of Appeals for the D.C. Circuit, and moved for the case to be consolidated with similar ICR appeals (Matters, 2/29/08).

## *UG&E ... from 1*

documented based on a response by UG&E in its monthly marketing report.

The confirmation letter, according to Staff, provides customers with a written reminder that they have entered into an agreement to switch providers and have a limited amount of time to opt out of the agreement during the 30-day cooling off period.

Delayed letters deprive customers of being able to reconsider their decision before any termination fees apply, Staff explained.

The delays, "constitute a serious and material breach of switching protocol in violation of the statute protecting customers from unauthorized switching," Staff alleged.

Staff argued that UG&E should contact all customers who received a late confirmation letter and allow them to cancel service at no fee. Staff urged that UG&E be forced to make restitution to customers for any difference between what the customer paid under UG&E's rates versus what they would have paid their LDC for the entire time the customer was with UG&E. Staff estimated such cost at several hundred thousand dollars.

"Staff is also recommending that the Commission assess stiff penalties on Universal, to make a clear and firm statement to Universal and all other AGS providers that such egregious and brazen misconduct against Michigan residents will not be tolerated."

UG&E's motion for clarification of the investigation's scope (Matters, 5/6/08), "ranks among the most outrageous and bizarre filings by this company to date," Staff added.

Staff also blasted UG&E for reporting that its door-to-door marketing firm, which has been working for UG&E since June 2007, had filed an application to do business in Michigan with registration pending, but omitting the fact that the application was filed on April 18, 2008, the same day as UG&E's response to the PSC on the matter.