Energy Choice Matters

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CenterPoint Smart Meter Initial Deployment to be Driven by REPs

Calling the implementation of smart meters a "transforming event" for the ERCOT market, CenterPoint Energy filed for approval of the initial deployment of up to 250,000 advanced meters as driven by REPs.

The advanced meters, through improved ERCOT settlement, should lower supply procurement risks for REPs, since actual customer usage can be used for wholesale market settlement instead of load profiles, CenterPoint told the PUCT (35639). Improved settlement will also more accurately assign the cost of unaccounted for energy (UFE) that is uplifted to the market.

CenterPoint sees the meters bringing more market competition as well. By helping to lower market prices and demand volatility while improving price transparency, the advanced meters should help lower the business risk related entry barriers for new REPs, the TDSP suggested.

The advanced meters' distributed generation metering may also motivate small retail electric customers to make more use of competitive renewable technologies such as wind and solar distributed generation devices, CenterPoint added.

The meters' remote connect/disconnect feature will facilitate the provision of prepaid and other innovative services by REPs, CenterPoint observed, thereby making service more accessible to consumers who cannot afford to make deposits, while lowering the risk to REPs of late or defaulted payments.

The smart meters could eventually lead to the elimination of ERCOT's Emergency Interruptible Load Service (EILS) program, given demand response prompted by the meters, CenterPoint suggested.

CenterPoint proposed reducing its tariffed Move In charge for premises equipped with the smart meters, producing savings for customers.

However, many of the meters' most innovative features cannot be fully exploited under current

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UG&E Steadfast Against Staff's Suggested Product Changes

The Michigan PSC does not have the authority to regulate the rates, fees or contract length of alternate gas suppliers, Universal Gas & Electric argued in a motion to clarify the scope of the Commission's investigation into UG&E's marketing (Matters, 5/1/08).

The PSC Staff, UG&E reported, is intent on lowering UG&E's termination fee from $250 to $100 and also eliminating its five-year product in favor of a two-year contract.

But the PSC is a creature of statute, UG&E pointed out, and while statute gives the PSC power to ensure proper solicitations and disclosures, and to prevent slamming, statute does not give the PSC any power over AGS rates or terms, UG&E noted.

The Staff, UG&E claimed, has acknowledged that it does not have authority to regulate UG&E's termination fee, but is still insisting UG&E change it.

The Staff has also not shown why UG&E should be compelled to lower its fee to $100 when competitors are charging $150 exit fees for shorter term contracts, UG&E argued.

Staff has objected to UG&E's requirement that customers pay termination charges before UG&E returns customers to LDC service.

Aside from that being a contractual provision which is outside of the PSC's jurisdiction, UG&E asserted that the Gas Customer Choice tariffs do not give the customer the right to switch suppliers

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Maryland PSC Warns of Competitive Imbalance in PJM Demand Response Market

PJM's proposed demand response aggregation rules need to be fixed to prevent distribution utilities from gaining a competitive advantage in the market, the Maryland PSC cautioned in comments filed at FERC (ER08-824).

The proposed aggregation rules, packaged with reforms to PJM's customer baseline mechanism, are intended to encourage additional demand response (Matters, 4/16/08).

But the PSC explained that registration and payment for participation in the economic demand response program currently takes place at the electric distribution company level.

Those steps should occur at the RTO level, the PSC urged, since under the current system, "there is the potential for electric distribution companies to cut out the curtailment service provider, without whom the demand responder might never have come to market."

"Requiring demand responders to register with the electric distribution company provides the electric distribution company all of the information necessary to steal the customer from the curtailment service provider," the PSC cautioned.

Measurement and verification can be done by the RTO and subsequently reconciled by the electric distribution company, the PSC suggested.

EnerNOC Buoys Management Business By Buying South River Consulting

In a move that further strengthens its growing energy procurement consulting and management portfolio, EnerNOC acquired for $4.75 million privately-held South River Consulting, the Baltimore-based consultant that had over 200 clients.

South River has also been a go-to source for risk analysis by Maryland policymakers, and had filed testimony supporting an active portfolio management approach to SOS on behalf of PSC staff in proceedings such as Case No. 9117.

EnerNOC said while it will evaluate individual opportunities for such non-procurement policy consulting on a going-forward basis, such policy consulting activities won't be a "core activity."

The acquisition gives Boston-based EnerNOC a physical base in PJM and is an attempt to differentiate the demand-response provider from its competitors by expanding its suite of products.

EnerNOC had previously acquired consultant MDEnergy last fall, and offers an online reverse-auction technology platform.

Briefly:

Shell Eyeing Illinois Electric Market

Shell Energy North America applied for an Alternative Retail Electric Supplier license at the ICC (08-0299).

REPs Oppose CHP Portfolio Standard

Creating a portfolio standard for Combined Heat and Power in Texas (similar to RPS) would, "create a major new subsidy for a well-established segment of the electric industry," Reliant Energy and the Alliance for Retail Markets told the PUCT in joint comments (34934). The Texas Combined Heat and Power Initiative suggested such a program as part of the PUCT's CHP report to lawmakers (Matters, 5/5/08), but Reliant and ARM pointed out that the CHP industry is well established in Texas, so much so that the state leads the nation in CHP. "The result of creating a new subsidy through a CHP RPS will be a transfer of wealth from end use customers - through higher retail electric bills - to CHP owners who do not need the subsidy," Reliant and ARM cautioned.

CAISO Suggests Oct. 1 Date for MRTU

The California ISO is "anticipating" an Oct. 1, 2008 Go-Live date for its Market Redesign and Technology Upgrade, it told FERC in its latest monthly status report. Although the ISO board is to select a firm date this summer, the anticipated date is the first marker the ISO has reported to FERC since pushing MRTU's start into the fall.

TXU Touting Efficiency in Four Cities

TXU Energy is bringing its Home Energy Makeover Tour to Dallas, Midland, McAllen, and Corpus Christi this year, which shows local homeowners several low-cost energy efficiency measures. TXU will also use the tours to promote its Energy Power Monitor, which it bundles with certain of its offerings. The monitor uses a home's existing electrical wiring to display near real-time data including a running total of estimated energy cost.

National Grid Files for Efficiency Programs in N.Y.; Starts KeySpan Rebranding

National Grid proposed a $220 million, three-year electric and gas energy efficiency plan to the New York PSC that would tack on $1.50 to an average customer's single-commodity bill (08-M-0484). Grid expects customers to reduce energy use by approximately 4.4 million MWhs and 8.5 million MMBtus, saving more than $350 million. Grid is launching a new brand campaign with the tagline "The power of action" to connect to individual actions customers can take to save energy and the environment. Grid is also rebranding its KeySpan units as National Grid and expects the conversion to be completed by the end of the year.

CRA Study Bolsters RPM, EPSA Says

EPSA pointed to a new study called "Reliability at Stake" by Robert Stoddard of CRA International as highlighting the value of PJM's RPM capacity market. Stoddard notes that customers bear the risks of regulated central planning, risks that increase in uncertain waters. Stoddard also cautions that the "specter of a complete regulatory overhaul of the resource adequacy mechanism in PJM, however, is an enormous and unnecessary risk facing investors today." Such regulatory uncertainty may be a self-fulfilling prophecy, he notes, since the risk may deter investment.

PJM Sees Adequate Summer Power

PJM forecast adequate power supplies for the summer and expects peak electricity use to be higher than last summer but below the all-time record. PJM projected a peak of 137,950 MW, with its 159,780 MW of committed capacity producing a reserve margin of 19.7%.

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while the contract is still in its initial term.

"'Customer Choice' does not mean that customers are free to enter into binding contracts and breach those contracts at will without penalty," UG&E argued.

By tariff, the customer does not have the right to contact the utility and demand to be returned to LDC supply, UG&E reported. The request must be made by an AGS.

UG&E also questioned why the Commission permits the utilities to keep customers who return to LDC supply from competitive supply from shopping again for 12 months if customers truly have an unfettered ability or absolute right to make supply choices at any time.

In fact, UG&E noted the tariff is specific in enumerating five express circumstances under which a return to LDC supply is permitted during the initial contract term, and pointed out that an agreement between the customer and the supplier is not one of those enumerated circumstances.

For that reason, UG&E suggested that the tariff appears to prohibit UG&E from returning customers to LDC supply during the initial term of a contract even where the customer pays a termination fee. The tariff would permit a change to another AGS under such circumstances, UG&E reasoned.

Preventing UG&E from offering a five-year product would deprive customers of choices, the marketer claimed, and customers are more likely to realize higher savings in the later years of their five-year deals. Thus, cutting the product to two-years would deprive customers of the greatest savings, UG&E observed.

UG&E has about 1,500 customers in MichCon territory paying UG&E's initial offering price of $0.999/Ccf, while MichCon's price rose to $1.005/Ccf on April 1.

The wholesale price for two-year natural gas is currently higher than the wholesale price for five-year natural gas supply, as the forward pricing curve is inverted, UG&E pointed out. A two-year product would currently carry a higher per-Ccf rate.

UG&E wants staff to inform customers calling the PSC about their UG&E contracts of the LDCs' current GCRs.

UG&E thinks most calls to Staff are driven by inaccurate media reports of UG&E's prices relative to the GCRs, and think customers would not be concerned if they knew that MichCon and Consumers are currently charging $1.005 and $0.89 per Ccf respectively, in comparison to UG&E's contract prices of $0.999 and $1.049.

Staff has refused UG&E's request to provide such information to customers, but UG&E thinks Staff's provision of such information would lessen customer confusion, since customers trust Staff.

"The problem has become so bad that customers are actually demanding UGE to cancel contracts where UGE's price is lower than the current price being charged by the Utility," UG&E reported.

UG&E told the PSC it cancelled contracts for

27 customers in the MichCon service area who were paying UG&E $0.99/Ccf but will now pay MichCon $1.005/Ccf.

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Commission Rules, ERCOT Protocols, or Market Guidelines, and changes may be appropriate. Those features include:

• Transmission and processing of 15-minute interval usage data for use in customer billing and wholesale market settlement;

• Processing switches on a real-time or same-day basis;

• Processing move-in and move-out transactions on a real-time basis; and

• Processing switch, move-in, and move-out transactions through CenterPoint's web-based portals.

While CenterPoint develops its backoffice systems during the first nine months of initial deployment, REPs will be required to provide a forecast of the number and location (by zip code) of the advanced meters they require.

Those forecasts will be due approximately 2-3 months into the initial deployment period, or about 6 months before CenterPoint begins installing meters.

CenterPoint will deploy meters in response to REP requests on a first-in, first-out basis. Actual deployment would be the lesser of 250,000 advanced meters, or the number of meters that can be supported by 6,000 cell relays, as requested by REPs.

Meters will be deployed at a rate not to exceed approximately 9,200 meters per month and may be deployed only in areas already covered by a communications network.

At the end of each quarter, CenterPoint will allocate meters and cell relays among all REPs according to each REP's percentage of the market at the time of allocation. For example, a REP with 10% of the market would receive an allotment of approximately 920 meters.

REPs may reject any meters allotted to them. Meters that are not scheduled for deployment when the quarterly allocation is made will be reallocated to participating REPs, based on each REP's percentage of market share at the time of the allocation. Meters not scheduled for installation at the end of each quarter will not be reserved for REPs, and will be allocated.

CenterPoint intends to hold at least two REP workshops to get feedback on meter installation activities, with the first workshop slated for December 2008. Follow-up meetings will be held every 2-3 months as needed.

Much of the customer interaction with the meters will occur via web portals. There will be no charge to REPs for core web portal support, which allows REPs to access the Meter Data Management System (MDM) repository for the latest meter reading, usage history, and power status checks. The costs of core web portal support are to be recovered through an initial deployment surcharge.

However, on-demand access requiring direct communication with a meter (rather than the MDM) for information, such as on-demand meter reading or real-time power status check, will be charged an access fee. REPs requiring custom, nonstandard metering or advanced features may incur additional charges as allowed by P.U.C. SUBSTR. 25.130(g)(2)(A-D).

The Itron OpenWay CENTRON meters picked by CenterPoint will satisfy all of the functionality requirements in the Commission's rules, CenterPoint reported, including: automated/remote metering; two-way communication; remote disconnect and reconnect ability for meters at or below 200 amps; capability to time-stamp data; direct, real-time access for end-use customers and their REPs; price signaling capability; 15-minute or shorter interval data; on-board meter storage of data; open standards and protocols; capability to communicate with on-premises devices; and ability to upgrade these capabilities as technology advances.

CenterPoint's smart meters are open architecture, and can function with ZigBee home area networks, allowing them to interact with monitoring and control devices inside a customer's premise.

CenterPoint's advanced meter communications network will initially rely on General Packet Radio Service (GPRS) but could eventually include wireless links, Ethernet connections, broadband over power lines (BPL), microwave, and fiber optic technologies to efficiently transmit meter data.

CenterPoint applied for a surcharge to recover costs of the deployment plan. The surcharge would include a usage-based infrastructure component applicable to all non-IDR metered retail customers in the applicable rate classes immediately upon Commission approval and effective for eight years, and a per month meter component applicable only to those retail customers with an installed advanced meter and effective for five years:

Rate Class	**Infrastructure Surcharge**	**Meter Surcharge**
Residential	$0.001728 per kWh	$4.75
Secondary <= 10 kVA	$0.002399 per kWh	$10.46
Secondary > 10 kVA	$0.029637 per kVA	$10.46
Primary	$0.006334 per kVA	$10.46

The values above are based on the PUCT granting CenterPoint interim rate relief.

CenterPoint projects investing $256 million in capital expenditures and $145 million in operation and maintenance costs through 2016 to support the initial deployment.

Long-term protection against future disallowances based on creative hindsight and second-guessing will be critical to obtaining and maintaining on-going approval from CenterPoint's board of directors for smart metering, the TDSP told the PUCT.

Since the advanced meters are leading edge technology, CenterPoint cautioned that it will be constantly learning and adjusting as it executes its deployment plan, and that even with reasonable and prudent management, "cost increases will often result from unforeseeable technological hurdles."