Energy Choice Matters

September 15, 2009

Texas Load Representatives Seek Extension of Period in which Termination Fees Prohibited

The prohibition on REP termination fees should be extended from only 14 days prior to contract expiration to the entire time period after a REP sends a renewal notice to a customer, several load representatives said in comments on a PUCT rulemaking to harmonize renewal notice rules with recent legislation (37214). Due to the related nature of renewal notices and the end date of contracts, several stakeholders addressed requirements for listing the end date of fixed contracts on bills in their comments in Project 37214, however, coverage of those comments are included in our related story on Project 37070 (see story below).

Project 37214 mainly addresses longer renewal notice periods for residential customers on fixed price contracts, with a proposal for publication requiring the notice to be sent 30-60 days before expiration, rather than 14-45 days as in the current rule (Matters, 7/27/09). Under the current rule, REPs may not charge a termination fee to customers 14 days before contract expiration, and the proposal would not change that requirement.

However, the Steering Committee Of Cities Served By Oncor, as well as the Texas Ratepayers' Organization to Save Energy, Texas Legal Services Center and AARP Texas, argued that the termination fee prohibition should be lengthened. Cities argued that with the longer notification timelines, REPs will be allowed to charge a termination penalty to a customer even after having notified that customer that the customer's contract is expiring. "As a consequence, any customer who has received notification of contract expiration must still wait at least two weeks before switching.

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Load Representatives Push for Specific End Date for Fixed Contracts to be Listed on Texas Bills

REPs should be required to include the exact date of a fixed price contract's expiration on bills for all customers, not just mass market customers, several load representatives said in a PUCT rulemaking to implement several statutory changes made in this year's session (Project 37070).

In order to implement various billing provisions of HB 1799 and HB 1822, a proposal for publication would allow REPs to estimate the end date of fixed price contracts which must be included on bills (Matters, 7/24/09). Contained in PUC Subst. R. §25.479, the rules could be waived by non-residential customers with demands in excess of 50 kW.

The proposal allowing the use of estimated end dates for contracts, "contradicts the clear, black-letter requirements of HB 1822 as they relate to the expiration of contracts," the Steering Committee of Cities Served by Oncor said. The Cities noted that the legislation states "unequivocally" that, "[a] retail electric provider shall include on each billing statement the end date of the fixed rate product."

The Cities dismissed arguments from REPs that they cannot know a specific end date due to the fluid nature of the TDU meter reading schedule by claiming, "REPs nonetheless have no problem assigning an end date to a contract when it benefits the REP to do so, i.e. when the REP wants to charge early termination fees."

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TXU, Reliant Offering to Purchase Excess Distributed Renewable Generation

TXU Energy and Reliant Energy have both launched plans to purchase the excess distributed renewable generation of customers, joining Green Mountain Energy in making the option available.

Unlike Green Mountain's plan (Matters, 5/11/09), both TXU's and Reliant's buyback programs are an "add-on" to the customer's existing product, with the customer retaining their existing rate and applicable terms and conditions. As an add-on, the rate for excess generation is not tied to the rate that the customer pays for consumption, as is the case (for the first 500 kWh) at Green Mountain.

TXU Energy's program is distinctive in that it pays a different rate for excess solar and wind power, reflecting solar's peaking nature and corresponding higher wholesale rates for excess generation at such times. TXU pays 7.5¢/kWh for excess solar power and 6.0¢/kWh for excess wind. The prices are the same regardless of TDSP area.

Reliant's program pays a flat rate regardless of distributed generation type, but does vary by service area. At CenterPoint, excess generation is paid 8.5¢/kWh, and at Oncor, excess generation is paid at 7.2¢/kWh. Reliant said rates are based on historical values of wholesale power (January to December 2008).

TXU's program requires the customer to sell associated RECs with their surplus generation, although the REC value is minimal given the low production from most residential distributed systems. Reliant currently does not purchase customer RECs but is considering such purchases.

John Geary, Vice President of Innovation for TXU, said that interest among customers has been "pretty strong," with TXU first marketing the product to its customers who the REP knew had distributed renewable energy installations. Launched in July, Geary said the product has outpaced other launches from TXU, and that it has attracted some customers from other REPs.

Reliant said that it expected interest to further increase as the price of solar power installations becomes more affordable.

CenterPoint, AEP Recommend Changes to TCRF Process

CenterPoint Energy and the AEP Companies have both asked the PUCT to adjust the transmission cost recovery factor (TCRF) rules so that distribution service providers (DSPs) can recover all transmission costs they incur. The recommendations came in a PUCT rulemaking examining Subchapters H through J of Chapter 25 of the Substantive Rules.

Neither CenterPoint nor AEP explicitly recommended more frequent updates to the TCRF imposed on REPs -- a solution suggested by Oncor, as exclusively reported by *Matters*. But both TDUs said that changes are needed to prevent a mismatch in the timing of new wholesale transmission rates collected from distribution service providers, and TCRFs charged by distribution service providers and collected from REPs (Only in Matters, 7/13/09).

The AEP Companies said that, "[t]he TCRF rule should be amended so that DSPs are authorized to fully recover increased transmission charges in a timely manner. Currently, transmission service providers' interim transmission cost of service (ITCOS) updates may be filed once a year at any time during the calendar year, while TCRFs can only be updated on March 1 and September 1 of each year. Due to this mismatch, the DSP could potentially under-recover its full cost of service for several months."

CenterPoint Energy used more general language, requesting only that distribution service providers be given, "the opportunity to recover the full costs paid to the [Transmission Service Providers]."

Both AEP and CenterPoint cited higher transmission costs in the near future from Competitive Renewable Energy Zone construction as necessitating more timely TCRF updates.

While theoretically the distribution service providers could be made whole without the need for more frequent TCRF updates (by true-ing up any unrecovered balance in new TCRF rates), CenterPoint also noted that a limit on the annual TCRF adjustments, "is expected to create cash-flow hardships for the DSPs," which would not be cured through a true-up -- all but asking the

Commission to allow more frequent changes to the TCRF charged to REPs.

The Commission is to examine the frequency of Transmission Cost of Service (TCOS) updates, and related issues, in a comprehensive rulemaking after denying a narrowly tailored TCOS petition (Only in Matters, 8/27/09).

FERC Rejects PJM Limits on Retail Regulators' Authority to Set Load Response Eligibility

FERC rejected PJM's proposal to require relevant retail regulatory authorities to either allow all customers to participate in the RTO's demand response programs, or bar all customers from the programs, as FERC said PJM's condition would, "excessively limit a retail regulatory authority's ability to condition the eligibility of its retail customers."

The Commission held that Order No. 719-A clarified that relevant retail regulatory authorities retain, "substantial flexibility in establishing requirements for eligibility of retail customers to provide demand response." Accordingly, PJM's proposal requiring that all customers must be able to participate if any customer participates was denied (Matters, 3/4/09). PJM was directed to revise its tariff to recognize a retail regulatory authority's ability to condition a customer's eligibility, consistent with Order No. 719-A. The ruling opens the door for municipals to contract with an exclusive curtailment service provider to offer customers demand response services, while denying customers the ability to participate in the PJM markets with other providers.

FERC stressed, however, that demand resources that have already cleared the RPM auction shall not be affected by any eligibility requirements subsequently imposed by a relevant retail authority for the period under which they have cleared RPM. "We are concerned that the reliability-centered purpose for which the RPM tariff construct was established could be undermined if policies adopted by a retail regulatory authority to restrict the eligibility of demand to participate in the RPM market were implemented in a manner that requires changes to the results of completed RPM auctions," FERC said. Such demand resources will be subject to the relevant retail authority's eligibility requirements for future RPM auctions.

While FERC granted an exemption for RPM-cleared resources, FERC refused to grant a wavier from any potential new eligibility rules for other demand resources under contractual obligations with a curtailment service provider, finding that outside of RPM, terminating a customer's eligibility as a demand resource does not warrant divergence from allowing the retail authority to set eligibility policies.

The Commission accepted PJM's proposed requirement that load serving entities seeking to assert that the laws or regulations of the relevant retail regulatory authority expressly prohibit an end-user's participation in PJM's demand response programs must provide the requisite certification to PJM within ten business days of receiving notice from PJM of a registration request.

Also receiving Commission approval was PJM's requirement that if a load serving entity seeks to assert that a state law or regulation bars retail customer participation, then the load serving entity must submit evidence to PJM regarding participation rights in PJM's demand response programs.

Elkton Gas Seeks Waiver of Consolidated Billing, First of the Month Switch Rules

Elkton Gas requested that the Maryland PSC grant it a waiver from certain provisions of COMAR 20.59 and 20.69 relating to the competitive gas market (RM 35), because of the cost burdens that required changes would impose on the small LDC.

Elkton Gas has 6,250 customers, of which only 520 are commercial and industrial. Elkton said in seven years of offering choice it has not had a single transportation customer.

In particular, Elkton said implementing utility consolidated billing and first-of-the-month enrollments would cost $376,000, or $60 per customer. Elkton Gas said such an increase would drive more customers to propane service, which competes heavily in Elkton's rural footprint. Customer migration off the LDC system would in turn increase the per-customer costs of maintaining the distribution system for remaining customers.

Elkton said that at its New Jersey affiliate, Elizabethtown Gas, utility consolidated billing was implemented at $500,000 at the request of one supplier, who later opted to continue dual billing.

Doubting the benefits of either utility consolidated billing or first of the month enrollments, Elkton Gas asked for a waiver of both requirements.

Elkton said it will comply with all other provisions of COMAR 20.59 and 20.69

PJM Proposes Sell-Backs of RPM Capacity due to Delayed Transmission

PJM filed additional RPM tariff changes at FERC to revise the incremental auction provisions to provide for the release of previously committed capacity on the unconstrained side of a delayed Backbone Transmission upgrade to match the additional capacity committed on the constrained side (Matters, 9/2/09).

Such sell-backs are to be accomplished through the regularly scheduled incremental auction following the conditional auction in which the additional capacity for the constrained side of the project is procured, PJM said.

"This is appropriate," PJM stated, "as the only reason to hold an unscheduled conditional auction is to ensure that a reliability violation is addressed promptly. Any resulting need for a sell-back presents an equity or economic issue that can be fully addressed before the Delivery Year using the regularly scheduled incremental auctions."

PJM proposed that the total megawatts of sell-back in the unconstrained parts of the region shall match the total megawatts of additional capacity committed in the constrained parts of the region as a result of the Backbone Transmission delay, so that the overall level of capacity committed does not change

"[C]apacity committed in the Base Residual Auction above the target reliability requirement should not be sold off in the incremental auctions, to avoid degrading the value assigned to that capacity by RPM's sloped variable resource requirement curve," PJM said.

Briefly:

Georgia Natural Gas Marketing Recycled Gas Product

Georgia Natural Gas (SouthStar) yesterday claimed to be the state's first and only natural gas marketer to obtain recycled methane gas from a landfill for customer use. Georgia Natural Gas began purchasing the recycled gas in early 2009, contracting for the exclusive right through 2011 to the entire output of Jacoby Development's Georecover-Live Oak facility. Georgia Natural Gas launched a marketing campaign regarding its recycled gas this week, including television, radio, billboards, print, direct mail and online marketing efforts.

Constellation NewEnergy, Providence Chamber Sign Aggregation Pact

Constellation NewEnergy and the Greater Providence, R.I., Chamber of Commerce announced a electric aggregation program yesterday (the Providence Power Program), which was touted as allowing the chamber's small- to medium-sized businesses to pool their electrical load to gain access to better prices and more services that might normally only be available to large commercial and industrial customers. Constellation pointed to the expiration of the transitional Standard Offer Service mechanism at the end of 2009 as making the aggregation attractive to customers. Aggregation members will also be able to access other products in Constellation's suite such as load response and renewables.

GDF Suez Says It Is Second in KEMA Rankings

GDF Suez said yesterday it has risen to second place (from third) in KEMA's latest commercial and industrial sales ranking. GDF Suez said that the KEMA rankings showed an estimated 15 TWh increase since August 2008, which Suez said includes more than 4.8 TWh in annualized sales over the past six months. The nearly 40% growth has been entirely organic. Also aiding Suez's rise was the cannibalization of the load of perennial second-place supplier RRI Energy by Hess and NRG Energy. Although Suez did not disclose actual sales, based on its statement that the estimated 15

TWh growth represents about a 40% increase, its sales estimates were approximately 37.5 TWh in the 2008 ranking, and 52.5 TWh in the current ranking. Suez said it serves over 50,000 accounts for a total contracted load of 7,150 MW. Suez serves customers between 50 kW to 200+ MW in Delaware, Texas, Massachusetts, Maine, Maryland, New York, New Jersey, Pennsylvania, Illinois, Connecticut, and Washington, D.C.

Md. Utilities Announce 2009-10 SOS RFPs

The Maryland utilities formally announced their scheduled SOS procurement for 2009-2010, starting with the October 2009 procurement. In total, the utilities are seeking 4,526 MW, including:

- 656 MW for Allegheny Power
- 2,452 MW for Baltimore Gas & Electric
- 342 MW for Delmarva Power
- 1,076 MW for Pepco

Renewal Notices ... from 1

This inconsistent application of customer protection rules creates an improper burden for the consumer and is bad for competition, as it exacerbates customer 'stickiness' in the market," Cities said.

However, the scenario described by Cities is not unique to the proposal for publication, and occurs under the currently approved rule, as REPs have a window of 45 days to 14 days prior to expiration to send the renewal notice. REPs sending the notice out earlier in this window will be sending the notice to customers prior to the period when the termination fee prohibition takes effect, so the issue does not arise only from the proposed changes in the timeline.

Nevertheless, Cities and Texas ROSE et. al. both recommended that REPs be prohibited from charging early termination fees once the customer receives notice of the their upcoming contract expiration, which for residential customers is at least 30 days prior to expiration.

The provision of an Electricity Facts Label (EFL) for the default renewal product also drew attention from several stakeholders. Under the proposed rule, the EFL is not required with the renewal notice, but must be subsequently delivered to the customer through the same delivery method as the renewal notice, at least 14 days before contract expiration.

Texas ROSE said that the EFL for the "new" product should be included in the initial expiration notice. The Oncor Cities argued that if the EFL is not provided in the initial notice, the notice should include a disclaimer that: (1) customers not taking any action will receive service on the default product; (2) the REP cannot currently project rates for the default product; and (3) customers who receive the default renewal product may experience "substantially different -- and possibly higher -- rates."

The Texas Energy Association for Marketers, however, recommended that contract expiration notice should disclose where the default price can be obtained, but should not require a separate mailing of that price (and associated EFL). TEAM noted that HB 1822 does not include any statutory requirement for the REP to disclose the default renewal price prior to the expiration of the contract. TEAM further argued that the proposed rule's timeline may produce customer confusion, as a customer may quickly choose a new product or switch to another REP upon receiving their expiration notice 30-60 days before expiration. However, the customer would then receive, up to 14 days before expiration, an EFL for a default renewal product from their old REP, which could lead customers to believe their choice or switch was not honored.

REPs Ask for Changes to Enrollment Authorization Requirements

TEAM, in separate, joint comments with the Alliance for Retail Markets, CPL Retail, Direct Energy, First Choice Power, Gexa Energy, Green Mountain Energy, Reliant Energy, Stream Energy, TXU Energy, and WTU Retail also recommended changes to PUC Subst. R. §25.475 not contemplated by the proposed rule, but are prompted by rule changes adopted in March 2009 which the REPs said have proved burdensome.

Specifically, a March 2009 rulemaking (35768) added a provision that the affirmative consent required for enrollments must include the ESI ID in each consent recording, electronic document, or written consent form. Authorizations must also include the identification number of each Terms of Service and EFL.

"However, REPs are finding that implementation of this provision is cumbersome and not beneficial to customers. Customers generally do not know their ESI IDs. Nevertheless, REPs are being required to read the 22-digit number to the customer, which is time-consuming, disruptive to the call, and confusing to the customer," the REPs said.

"[T]he requirements to read the identification numbers for the terms of service and EFL documents are similarly time-consuming and burdensome. These requirements ultimately provide customers with no additional benefit or protection, yet increase call times, costs to the REP, and customer frustration."

The REPs asked that the ESI ID, Terms of Service identification number, and EFL identification number be stricken from the enrollment verification requirements.

The Office of Public Utility Counsel and the Oncor Cities sought to expand residential protections to small commercial customers. Specifically, HB 1822 only requires that residential customers be informed of termination fees in their renewal notice, but OPC said that small commercial customers should receive a similar notice.

However, the REPs opposed the proposed requirement to include the specific amount of termination fees in the residential renewal notices, arguing that HB 1822 only requires a "description" of such fees. "[T]he fees may vary significantly depending on which product the customer is on and depending on the date the notice was received, and it would be costly to have to customize these notices to each individual customer," REPs noted.

The Oncor Cities said that the notice timeline for small commercial customers (currently 14-60 days) should mirror the proposed new residential timeline of 30-60 days.

REPs objected to the proposed requirement that residential expiration notices must be both mailed and emailed. REPs argued that sending notices through both delivery methods will create confusion if a customer takes action immediately upon receiving an email notice, but later receives the same notice through the mail several days later. Furthermore, sending mailed notices to customers who have requested paperless billing and communication may cause customer complaints from those who have informed the REP they do not wish to receive paper communication for convenience or environmental reasons, REPs said. While HB 1822 requires REPs to send a mailed "and" emailed notice, REPs argued that under statutory construction, the Commission can consider consequences of a particular interpretation in implementing the statute.

The REPs asked that the proposed rule changes not take effect until March 1, 2010, citing various logistical concerns. Furthermore, REPs stressed that, consistent with the updated rules adopted in March 2009, the revised rules should hold that the changes do not apply to existing contracts.

REPs Seek Clarification on Variable Rate TDU Pass-Through

Separately, Reliant Energy, Gexa Energy, Green Mountain Energy, and Stream Energy asked for clarification regarding the pass-through of changes in TDU, ERCOT, Texas Regional Entity, and similar regulatory charges outside of the REP's control for variable priced products. The four REPs noted that while new PUCT rules explicitly allow for the pass-through of such changes under fixed and indexed products, no provision is made to allow for the pass-through of such changes on variable rates.

Although variable rates may change every month, the four REPs still noted there are times when they will be unable to change the rate to reflect revised TDU or other charges in a timely manner. For example, when a REP offers a customer a new product, the EFL for that product must list the price to be charged for the first month of that product. In the time between when the customer enrolls with the REP, and when the first bill is due, the TDU (or similar) charges may change, the four REPs noted. A similar scenario can occur at the end of a contract if the customer is presented with a variable price EFL up to 60 days ahead of the expiration date, the four REPs noted.

The four REPs asked that the requirement that the price on the EFL must equal the first month's price should only apply to costs or pricing elements within the REP's control. The requirement should not limit the REP's right to revise the variable rate for pass-through charges outside its control, the four REPs said.

End Date on Bills ... from 1

Fox, Smolen & Associates suggested that estimated end dates be permitted (based on the TDU meter read cycle), but said that once the billing cycle schedule for the TDU is known for the year in which the contract expires, the REP's actual end date shall be consistent with the TDU meter reading schedule for the customer during the month of expiration. If the TDU's actual meter reading varies from its published schedule, there shall be no termination fees or other fees imposed on the customer for a period of 14 days before or after the actual switch date occurs, Fox, Smolen & Associates recommended.

In comments in Project 37214, several REPs pointed to a logistical problem associated with using the TDU meter reading cycle to estimate a contract end date as proposed under the rule. Because the Commission recently reduced the standard switching time to only seven days, the end date of a term contract may not coincide with the TDU's meter reading schedule, REPs noted.

Load representatives also argued that HB 1822 requires the contract end date to be listed on all fixed rate bills, not only residential customer bills. However, by including the rule in §25.479, without any express language to the contrary, customers above 50 kW could waive the end date requirement. Fox, Smolen & Associates argued that, "[t]he benefits of the requirements that the amendments to Substantive Rule §25.479 are seeking to provide will be negated by the current practice of most, if not all, of the REPs by using the customer protection waiver allowed in §25.471(a)(3), for customers with demand in excess of 50 kW, as part of their standard contracts."

The Office of Public Utility Counsel also contended that the customer protection waivers are generally non-negotiable portions of a REP's standardized form contract for small business customers above 50 kW, who must accept the terms and waive protections on a "take it or leave it" basis. "A disparity of bargaining power exists," OPC claimed.

Fox, Smolen & Associates recommended adding language to the rule stating that the end date requirement cannot be waived by any customer pursuant to §25.471(a)(3). OPC similarly suggested that the end date provision should be included in §25.25, whose provisions cannot be waived by large customers.

OPC further suggested that the threshold for the customer protection waiver should be increased from 50 kW to 500 kW, if not 1,000 kW.

Additionally, OPC encouraged the Commission to use its authority under §25.471(a)(3) to request copies of the customer protection waiver notices REPs must provide to customers, so that the Commission, "will have greater insight into these customers' limitations and lack of protections."

With regards to billing terms, the Oncor Cities said that REPs should be required to use only terms identified and defined by Commission rules. If a REP seeks to use some other term to describe a billing practice, that REP should first obtain approval from the Commission, Cities said.

Texas Ratepayers' Organization to Save Energy, Texas Legal Services Center and AARP Texas made the same recommendation, especially with respect to non-recurring charges.

"By including all allowable billing terms in the rule, the PUC can effectively monitor the fees being charged by REPs to assure that the fee is fair and does not constitute a late fee charge in excess of the five percent allowed by rule. For example a fee charged by a REP to send a disconnection notice, if allowable, should be defined in the terms allowed by the rule. If REPs are charging fees over and above the fee charged by the TDU for disconnection and reconnection the PUC should determine if those fees are allowable and define them in the rule," ROSE said

The Cities also objected to the proposed definition for "monthly charge" as vague, as the definition does not explain the charge's purpose, "and so therefore would open the door to abuse by allowing for the assessment of extra charges without explanation."

"If by 'monthly charge' REPs mean 'monthly customer administration' charge, then the PUC should ensure that it is named and defined as such. The definition should also make clear which market entity is responsible for this additional charge," Cities said.

Texas ROSE said that the term "bundled rate" should be defined, and that REPs should be required to make an itemization of the charges included in the bundled rate available on the REP's website.

Several REPs argued that the proposed rule should not include a section delineating required terms for unbundled charges, as the section causes confusion, and all common billing terms can be addressed in other sections of the proposed rule. The REPs jointly filing the comments included the Alliance for Retail Markets, CPL Retail, Direct Energy, First Choice Power, Gexa Energy, Green Mountain Energy, Reliant Energy, Stream Energy, the Texas Energy Association for Marketers, TXU Energy, and WTU Retail.

The REPs also asked that, to reduce confusion and maintain consistency in customers' prior bills, REPs be allowed to make non-material changes to the proposed terms in the Commission rule. For example, a REP should be allowed to replace "surcharge" with "charge" or "fee" or "factor," REPs suggested, and be permitted to add or delete a suffix from a term (using "previous meter reading" in lieu of "previous meter read"). Abbreviations should also be acceptable, provided that the abbreviation and the unabbreviated term are identified on the customer's bill, REPs said.

REPs requested that the Commission allow REPs until March 1, 2010 to comply with any adopted rules, due to necessary system changes.

The proposed rules would require REPs to post billing terms and definitions on their websites, but OPC asked that REPs also be required to annually send such information in a billing insert, to assist those customers who do not have internet access.