Energy Choice Matters

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# Cities Say PUCT Lacks Authority to Require Customers to Notify REPs of PPA Status

The PUCT lacks authority to require that governmental entities eligible for extended payment deadlines under the Texas Prompt Payment Act (PPA) must notify REPs of their eligibility, the Steering Committee of Cities Served by Oncor said in comments (36260, Matters, 7/16/09).

The Cities said that the Texas Comptroller of Public Accounts, not the PUCT, is given rulemaking authority to establish procedures for the administration of the Prompt Payment Act. Accordingly, the Cities argued that the Commission lacks authority to require customers to provide prior notification in order to fall within the provisions of the PPA.

The State of Texas similarly said that a notification mandate is not required under the Prompt Payment Act or PURA. Nor is a notification requirement desirable, the State said, as any such requirement would place an unnecessary burden on customers.

Even if the burden were placed on REPs to regularly poll customers regarding their Prompt Payment Act eligibility, the State doubted the mandate would be effective.

"Regularly polling all customers, informing them of the eligibility requirements and asking them to respond with 'proof' of eligibility would not necessarily get a positive response from each and every PPA-eligible customer and might even garner a number of 'false positives' from ordinary customers who are either confused or desirous of special treatment. Whether done through bill stuffers, mass mailings or phone calls, the effort would be unnecessarily burdensome both to providers and customers," the State said.

However, the Alliance for Retail Markets and the Texas Energy Association of Marketers said that given REPs' potential exposure to refunding amounts assessed in violation of the PPA, the

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# Oncor Suggests More Frequent TCRF Updates if PUCT Grants Twice Annual Interim TCOS

The PUCT should consider allowing distribution service providers to update their transmission cost recovery factor (TCRF) more than twice annually if the Commission approves a petition to allow more than once annual adjustments to the interim transmission cost of service (TCOS) of transmission service providers, Oncor said in comments (37221).

As only reported in *Matters*, the AEP Companies, Texas-New Mexico Power, Sharyland Utilities, LCRA Transmission Services Corporation and Electric Transmission Texas have petitioned the PUCT to allow transmission service providers to file interim TCOS filings twice annually, rather than once annually (Matters, 7/13/09).

Oncor took no position on the policy merits of the petition, but did ask that, should the Commission allow more frequent changes in TCOS, it should also make corresponding changes to the rule for setting the TCRF charged by distribution service providers to REPs and their customers. Absent such changes, Oncor said that the TCOS changes would exacerbate an existing problem associated with distribution service providers' inability to fully recover wholesale transmission charges in a timely manner.

Currently, distribution service providers may make changes to the nonbypassable transmission

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# CL&P Reports July Migration Stats, Revises Earlier Data

Connecticut Light and Power revised its monthly migration reports for all months of 2009 due to an unspecified error with regard to calculating Last Resort Service. The impact on numbers varied, but generally, for the most recent data which had been May 2009, the erroneous reports overstated the number of migrated accounts per supplier

| July '09 Electric Supplier Accounts | Residential | Business | Total | % of Supplier Customers | Change vs. June Total |
|---|---|---|---|---|---|
| CLEARVIEW ELECTRIC | 854 | 260 | 1,114 | 0.8% | 843 |
| CONSOLIDATED EDISON SOLUTIONS | 2,346 | 1,394 | 3,740 | 2.6% | 87 |
| CONSTELLATION NEWENERGY | 886 | 9,059 | 9,945 | 6.9% | 289 |
| DIRECT ENERGY BUSINESS LLC | 114 | 1,565 | 1,679 | 1.2% | 20 |
| DIRECT ENERGY SERVICES LLC | 24,290 | 5,308 | 29,598 | 20.5% | 5,371 |
| DISCOUNT POWER INC | 0 | 0 | 0 | 0.0% | 0 |
| DOMINION RETAIL INC | 50,597 | 11,230 | 61,827 | 42.8% | 2,373 |
| GEXA ENERGY CONNECTICUT, LLC | 13 | 888 | 901 | 0.6% | 154 |
| GLACIAL ENERGY OF NEW ENGLAND INC | 419 | 1,782 | 2,201 | 1.5% | 273 |
| GREEN MOUNTAIN ENERGY COMPANY | 0 | 0 | 0 | 0.0% | 0 |
| HESS CORPORATION | 311 | 400 | 711 | 0.5% | 29 |
| HORIZON POWER AND LIGHT LLC | 0 | 0 | 0 | 0.0% | 0 |
| INTEGRYS ENERGY SERVICES | 35 | 3,224 | 3,259 | 2.3% | (257) |
| LIBERTY POWER HOLDINGS LLC | 0 | 52 | 52 | 0.0% | (52) |
| MXENERGY ELECTRIC INC | 2,040 | 2,064 | 4,104 | 2.8% | 73 |
| PEPCO ENERGY SERVICES, INC. | 0 | 2 | 2 | 0.0% | 0 |
| PUBLIC POWER & UTILITY, INC | 17,382 | 3,662 | 21,044 | 14.6% | 2,274 |
| ROYAL BANK OF SCOTLAND | 0 | 0 | 0 | 0.0% | 0 |
| SEMPRA ENERGY SOLUTIONS LLC | 2 | 1,020 | 1,022 | 0.7% | 13 |
| SUEZ ENERGY RESOURCES NA | 8 | 760 | 768 | 0.5% | 90 |
| TRANSCANADA POWER MARKETING LTD. | 26 | 2,363 | 2,389 | 1.7% | (301) |
| WHOLE FOODS MARKET GROUP INC | 0 | 3 | 3 | 0.0% | 1 |
| WORLD ENERGY | 0 | 0 | 0 | 0.0% | 0 |
| ENERGY PLUS HOLDINGS LLC | 10 | 0 | 10 | 0.0% | 9 |
| Total All Suppliers | 99,333 | 45,036 | 144,369 | 100.0% | 11,289 |

## Aggregate Data

***Data as reported by CL&P***

**Customer Load - Suppliers and CL&P (MWh)**

| | Residential - SS | | Business - SS | | Business - LRS | | Total CL&P Territory | |
|---|---|---|---|---|---|---|---|---|
| | **MWh** | **% of Class** | **MWh** | **% of Class** | **MWh** | **% of Class** | **MWh** | **% of Total** |
| Suppliers | 87,355 | 10.9% | 374,885 | 61.2% | 463,424 | 91.4% | 925,664 | 48.2% |
| CL&P | 714,223 | 89.1% | 237,323 | 38.8% | 43,584 | 8.6% | 995,129 | 51.8% |
| Total | 801,578 | | 612,207 | | 507,008 | | 1,920,793 | |

**Customer Count - Suppliers and CL&P**

| | Residential - SS | | Business - SS | | Business - LRS | | Total CL&P Territory | |
|---|---|---|---|---|---|---|---|---|
| | **Customers** | **% of Class** | **Customers** | **% of Class** | **Customers** | **% of Class** | **Customers** | **% of Total** |
| Suppliers | 99,333 | 9.0% | 44,148 | 35% | 888 | 83.5% | 144,369 | 11.8% |
| CL&P | 999,738 | 91.0% | 81,714 | 65% | 175 | 16.5% | 1,081,627 | 88.2% |
| Total | 1,099,071 | | 125,862 | | 1,063 | | 1,225,996 | |

## RESA Says PES, AOBA Opposition to Customer Lists Meant to Protect Market Share

Opposition to Baltimore Gas & Electric's proposal to make customer lists available to competitive suppliers appears to be driven by the desire of some suppliers and brokers to maintain market share, the Retail Energy Supply Association said in comments at the Maryland PSC.

As only reported by *Matters*, Pepco Energy Services (PES) and the Apartment and Office Building Association (AOBA) have opposed BGE's petition. PES, in particular, argued that the dissemination of customer lists would unfairly harm suppliers that have been successful in winning load in the absence of the lists (Matters, 8/13/09).

"[I]t appears that both AOBA and PES oppose BGE's request simply to protect their own turf and are not concerned with any positive outcomes that can accompany the provision of customer lists," RESA said. RESA noted that AOBA's subsidiary, AOBA Alliance, is a broker licensed by the PSC. Furthermore, AOBA Alliance has a relationship with Pepco Energy Services as its supplier.

According to the AOBA Alliance website:

"These successful Maryland and District of Columbia offerings are the result of the AOBA Alliance's negotiation of terms and endorsement of services offered by Pepco Energy Services ("PES"). PES was chosen after the Alliance's evaluation of a number of alternative energy services suppliers. Currently, over one hundred (100) organizations representing a total load of over 465 megawatts have chosen to participate in Alliance offerings. This represents approximately 25% of Pepco's total load in the District."

Given their relationship, RESA suggested that the Commission inquire as to the true purpose and intent of AOBA's and PES' opposition to BGE's request, and, in turn, to promoting customer choice in Maryland.

RESA noted that the customer lists are designed to benefit customers by allowing more suppliers to offer more products, with competition among suppliers reducing prices. "PES apparently would prefer to limit choice in an effort to protect its market share," RESA noted.

RESA further countered legal arguments against the customer lists raised by PES and AOBA, noting that the Commission in 2001 approved the use of an opt-out process for customer notice and inclusion on the supplier lists. A PSC decision cited by AOBA regarding the need for customer authorization dates to 1998, prior to the Commission's finding that an opt-out process was consistent with state codes, RESA noted.

The National Energy Marketers Association likewise urged the PSC to expeditiously approve BGE's customer list proposal, noting about half a dozen states have used customer lists to make more choices available to customers.

## PPL POR Discount to Include Only Incremental Costs

PPL's Purchase of Receivables program to be instituted by January 1, 2010, is only to include "actual incremental costs incurred by PPL" in the discount rate, the Pennsylvania PUC said in a written order released last week regarding its adoption of several measures to reduce barriers to retail competition at PPL (Matters, 5/25/09).

"[B]ased on several years' experience during the transition period, it is the Commission's judgment that a viable POR program is an essential element to the creation of a competitive market for generation in Pennsylvania, as envisioned by the Competition Act," the Commission said in its final order.

The Commission maintained the POR mechanics proposed in its Tentative Order, namely that there will not be an all-in/all-out requirement, nor will billing revert back to the supplier if a customer is in arrears for more than 90 days. However, POR will only include basic supply service, though a working group is to address provisions for billing services not covered by purchase of receivables.

With respect to the issuance of customer lists, the PUC ruled that PPL shall advance its refresh of its customer Release of Information database from the first half of 2010 (as contemplated under its default service settlement), if all parties to the settlement agree to the change. The PUC gave parties 14 days to file their positions on the change.

Regarding both EDI 867 Monthly Usage (MU) and 867 Interval Usage (IU) data, the PUC held that such data must be communicated within one business day of the meter reading, or according to the utility's supplier coordination tariff if different. The Commission directed PPL to file a supplier coordination tariff supplement to indicate when a supplier is to be provided with 867 MU or IU data if it is not going to be available within one business day of the meter read. All other matters pertaining to timeframes and formats for communicating interval data were deferred to the pending smart meter procurement and installation plans submitted by the utilities. PPL expects to complete the automation of EDI 867 IU transaction data by January 31, 2010.

The Commission also granted PPL until the second half of 2010 to implement an EDI 814 Advance Notice of Intent to Drop (814 ND) transaction, which would inform suppliers of PPL's intent to terminate a customer's service.

The PUC rejected a proposal from the FirstEnergy utilities to require suppliers to provide all account numbers for each and every account the supplier intends to serve when seeking to obtain information on the customer. The FirstEnergy companies said such a requirement would eliminate confusion that may arise when enrolling a corporate entity or its independently owned locations, and would also reduce slamming, but the PUC held that, "this Commission is unaware of instances of 'slamming' of industrial and commercial customers since the inception of Customer Choice, and we reject FirstEnergy Cos.' recommendation in this regard."

## FERC Clarifies No Decision on 2010 RPM Scarcity Pricing Offset Yet Made

FERC clarified that it has made no determination that the scarcity pricing offset mechanism in PJM's current tariff must be replaced for the 2010 Reliability Pricing Model auction, in an order on rehearing (ER05-1410 et. al.).

In a March order, FERC had accepted, for the May 2009 RPM auction, PJM's proposed method to adjust the Energy & Ancillary Services offset with a true-up for scarcity pricing revenues that reflects the reference resources that would have been in service for the Delivery Year in which scarcity revenues are paid. The Commission directed PJM and stakeholders to address and resolve various concerns about how to calculate the scarcity pricing revenues in the Energy & Ancillary Services offset in the stakeholder process, and to file revised tariff provisions, if necessary, in time for the May 2010 auction.

The Illinois Commerce Commission subsequently asked FERC to clarify that an improved method to calculate the scarcity pricing offset must be in place before the May 2010 Base Residual Auction, raising concern that a capacity resource could earn double revenues in a particular year for both scarcity and capacity, while load in a zone could pay twice in a particular year - once in the form of scarcity payments and once in the form of capacity payments - but only receive the true-up four years later.

FERC clarified, however, that it has made no determination that the scarcity pricing mechanism in PJM's current tariff must be replaced for the 2010 auction. The Commission is only requiring PJM to address the stakeholder concerns and file a report on its progress before the May 2010 auction, "and file tariff revisions, if necessary, in time to be implemented for the May 2010 auction."

The Commission also clarified that until it accepts a change to the tariff, the triennial review of the Cost of New Entry remains a part of the PJM tariff. Although FERC has strongly encouraged the development of an automatic adjustment mechanism, parties retain full rights to comment on any such proposal if filed.

FERC granted rehearing regarding the use of "conditional" incremental auctions, to be used if, for example, a planned transmission upgrade was modeled in the Base Residual Auction (to enable delivery of capacity from an unconstrained area to a constrained one), but it becomes clear prior to the Delivery Year that the transmission upgrade will not be completed in time.

The ICC sought rehearing because PJM's conditional incremental auction proposal as accepted by FERC in March only addresses the harm caused by inaccurate modeling of new transmission lines to customers in the constrained PJM zones (allowing for the purchasing of additional capacity in the constrained zones), but does not address the harm caused by inaccurate modeling of new transmission lines on the unconstrained region of PJM. The ICC argued that PJM's proposal was not just and reasonable because it does not provide similar relief for customers in unconstrained zones by providing for the sell-back of excess capacity procured in the unconstrained region.

On rehearing, FERC directed PJM to provide further explanation of its tariff with respect to the possibility of selling back capacity in the event that previously committed capacity can no longer be delivered to a constrained area due to the failure of a planned transmission line to be placed into service.

However, while the ICC initially recommended that PJM re-run the capacity auction to address over-procurement in unconstrained zones in such situations, FERC held that the results of the Base Residual Auction commit PJM to paying the generators the prices determined in that auction. "Therefore, no basis exists to re-run the auctions," the Commission said.

FERC found an alternate proposal from the ICC, under which PJM would sell back unneeded capacity when the failure of a large transmission project renders previously purchased capacity unusable, merits additional examination and directed PJM to justify its proposed exclusion of a sellback provision for the conditional auction. If PJM elects to include a sellback provision in the rules for the conditional auction under a compliance filing, it must also explain how it proposes to allocate any savings resulting from such sellback of capacity, FERC said.

The Commission denied rehearing on most other issues raised by parties. Among other things, the Commission dismissed the Maryland Office of People's Counsel argument that Cost of New Entry (CONE) should not be based on the cost of a combustion turbine, as OPC argued that the most frequent new entrants into RPM at this point are not combustion turbines. FERC held, however, that units meeting peak demand efficiently should have an opportunity to recover their costs over time, even if mid-merit or baseload investments are the most frequent new entrants during some years.

FERC affirmed its earlier decision rejecting PJM's proposal to determine Net CONE for the rest-of-market region using a two-step process whereby: 1) PJM would calculate a Net CONE for each CONE Area using average energy prices for the entire CONE Area; and 2) PJM would use the lowest of those values for use as the rest-of-market Net CONE. FERC held that PJM's proposal could result in Net CONE used for the demand curve in the unconstrained export area being below the actual net cost of new entry in that area, and could thereby prevent entry into that area, due to the higher Energy & Ancillary Services offset.

The Commission also affirmed its decision to eliminate the Interruptible Load for Reliability provisions in RPM, and its finding that 2.5% is an appropriate level for the "holdback" of demand to be filled by incremental auctions.

FERC further denied rehearing requests to implement PJM's original proposal, rejected in March, requiring capacity resources to offer their output in the day-ahead energy market on an "economic schedule." The Commission maintained PJM's proposal is unclear.

The Commission likewise rejected rehearing of its decision to maintain the Minimum Offer Price Rule in RPM, meant to mitigate buyer-side market power. "A capacity market will not be able to produce the needed investment to serve load and reliability if a subset of suppliers is allowed to bid non-competitively to suppress market clearing prices," FERC said.

FERC also affirmed its rejection of extending the commitment period for the New Entry Price Adjustment, stating that extending the time under which new resources can lock-in a capacity price beyond the current three years, "goes beyond the justifiable need to protect against lumpy investment."

"The new entrants are guaranteed higher prices and assurances that are not available to existing suppliers. Moreover, while the new entrant is guaranteed its price, the extra capacity it introduces into the market will reduce the prices to existing suppliers," FERC said of a longer New Entry Price Adjustment, which had been supported by CPV Maryland.

CPower's rehearing request for a reduced credit deposit given the reduced penalty amounts for deficient sellers was also denied by the Commission.

# *Briefly:*

**UGI Energy Services Seeks to Expand Ohio Gas Marketing Authority**

UGI Energy Services has sought to amend its natural gas marketing license in Ohio to include aggregation of customers, and expand the customer types and utility areas served. Under its current license, UGI Energy Services has authority to market to non-residential customers at Dominion East Ohio and Columbia Gas, though operations to date have centered on Dominion East Ohio. It is now seeking authority to serve all customer classes in those two LDCs, and to serve all customer classes at Duke and Vectren Energy Delivery as well.

**First Choice Power to Withdraw Unused Certificate**

First Choice Power Retail, L.P. filed to withdraw its REP certificate (10102) as the entity has not served customers since the REP Certificate was transferred to it from First Choice Power, L.P. on January 8, 2007. First Choice serves customers under its unaffected First Choice Power Special Purpose entity (certificate 10008)

# *PPA ... from 1*

identification of customers to whom the statute applies is a piece of information critical to REPs in the billing of those customers.

While it may be self-evident that a particular customer falls within the definition of "governmental entity," the same may not be true for another customer that is likewise subject to the statute's billing and payment directives (e.g., a relatively obscure political subdivision of the state), ARM and TEAM noted.

"ARM and TEAM contend that a governmental entity to which the TPPA applies should be obligated to affirmatively communicate its eligibility under the statute to its REP. The governmental body cannot simply assume that the REP will or should know that the statute's billing and payment requirements -- as opposed to the Commission's rules promulgated pursuant to PURA -- apply to the customer."

"While the application of the TPPA to certain customers may be a matter of law, equity nevertheless dictates that such a customer must have an affirmative role in ensuring that the company providing retail electric service is aware of the statute's applicability to the customer's billing for retail electric service," TEAM and ARM added.

ARM and TEAM suggested that the information may be provided by the state agency or political subdivision in a communication initiated on its own accord, or in response to a request for information by the REP (including an application for retail electric service). "The absence of such an affirmative communication to the REP would preclude the customer from seeking any refund or credit for past overbillings assessed in violation of the TPPA," TEAM and ARM argued.

TXU Energy similarly said that the Commission should amend P.U.C. SUBST. R. 25.480(c) to require that customers must provide notice to their REP if they are eligible for PPA billing. The notice should be made at the time of enrollment, and REPs should be free to decide the best mechanism to collect such information, TXU said.

The State opposed adding language to the Substantive Rules requiring PPA-eligible customers to dispute an incorrect invoice from a utility as required by the PPA, since the proposed requirement is superfluous given statutory requirements, and is inappropriate for a Commission rule.

However, TXU favored including the requirement in the Substantive Rules, despite being superfluous, since including the requirement in the rule, "would serve as an additional form of notice to governmental entities that they should promptly dispute incorrect invoices under the PPA."

# *TCRF ... from 1*

service charge assessed to REPs outside of a full rate case through updates to the TCRF permitted on March 1 and September 1 of each year.

"While the TCRF filing process is generally administrative in nature and results in more timely recovery of transmission costs through distribution charges than if the TCRF was not in place, regulatory lag still exists," Oncor said, because there is a mismatch between interim TCOS filings for TSPs and the restrictions on when distribution service providers can file for changes to their respective TCRFs. Specifically, while an interim TCOS update can be filed at any time, the TCRF may only be updated on March 1 and September 1.

Accordingly, if a transmission service provider has an interim TCOS update approved April 1, a distribution service provider cannot implement a change to its TCRF that reflects an increased transmission charge until September 1, leading to underrecovery during a five-month period, Oncor said.

"This situation has only caused moderate under-recovery in the past, but with the advent of the CREZ build out, an increase in the number of TSPs that will be filing for ITCOS updates throughout the year, and a potential increase in the frequency that TSPs will be filing for ITCOS updates throughout the year, the under-recovery could be extreme," Oncor added.

The Steering Committee of Cities Served by Oncor and Texas Industrial Energy Consumers both opposed allowing more than one annual interim TCOS filing as inconsistent with the risk of regulatory lag inherent in utility investment.

The Cities argued that adjustments to rate recovery outside of a full rate case should be limited to extraordinary circumstances, and that the current once annual interim TCOS update already mitigates regulatory lag risk faced by transmission service providers. While the petitioners argued a second update is appropriate due to new CREZ investment which must be recovered, Cities called the petitioners' arguments "speculative."

Cities noted that based on Oncor's 2008 Earnings Monitoring Report, Oncor's transmission wholesale operations earned a return on equity of 17.67% under the current TCOS rules, which "vastly" exceeds any reasonable estimation of Oncor's regulated cost of equity.

The wholesale transmission investment for AEP Texas Central Company and AEP Texas North Company produced earned returns which were 111% of the overall system rate of return, Cities added, based on the 2008 Earnings Monitoring Report.

TIEC noted that the petitioners, in testimony in a CREZ docket, said that the current recovery mechanisms were adequate, with petitioners further stating, "No new or untested procedures are necessary for the Joint Parties to finance the CREZ facilities."