Energy Choice Matters
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PUCT Staff Draft Would Allow REPs to Estimate Contract End Date Listed on Bill

REPs would be allowed to estimate the expiration date of fixed price contracts by referencing the billing cycle and month, or approximate date of expiration, under a draft proposal for publication filed by PUCT Staff yesterday in project 37070.

The proposed changes to Substantive Rule §25.479 would implement various provisions of HB 1822, including use of common billing terms.

Staff's draft would hold that, "A REP shall include on each billing statement the date that a fixed rate product will expire. If the exact date is not known, the REP may estimate the expiration date by reference to the billing cycle and month or approximate date of expiration."

The draft proposal for publication also includes a series of defined terms to be used by REPs if applicable in their billing. The defined terms use "charge" to define amounts applied at the discretion of the REP, "fee" to define amounts that are designated by a governmental agency to be used for a specific purpose, and "tax" to define amounts that are designated by a governmental agency without a designated purpose.

If a REP presents its electric service charges in an unbundled fashion, it would be required use the following terms, if applicable, to the customer's bill: "demand charge," "energy charge," "monthly charge," "transmission and distribution service charge," "taxes and other fees." These terms would have the following definitions:

(A) Demand charge - any charge, other than a tax or other fee or a transmission and distribution service charge, that is assessed on the basis of the customer's demand;

(B) Energy charge - any charge, other than a tax or other fee or a transmission and distribution service charge, that is assessed on the basis of the customer's energy consumption;

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RESA Favors Elimination of Warm Transfer Requirement in ConEd ESCO Referral Program

The requirement that Consolidated Edison use a "warm transfer" process on a pilot basis as part of its expanded ESCO Referral program should be eliminated, the Retail Energy Supply Association said in comments at the New York PSC, stating ConEd's various concerns have merit. As only reported in *Matters*, ConEd is seeking rehearing of the requirement, which was imposed in a PSC order expanding the program to include new service customers.

In particular, RESA noted that proponents of the warm transfer process have said that when a customer is transferred to an ESCO's call center, the ESCO will be free to enroll the customer in any product that the ESCO offers, not only the discounted referral product. "This broad discretion appears to conflict with the requirements established by the Commission in connection with the referral program," RESA said. RESA said that under the Commission's order establishing guidelines for referral programs, the utility is obligated to enroll the customer in the referral program and no other program.

RESA agreed that other concerns raised by ConEd have merit, including logistical impacts on the randomness of the referral process, the difficulty in accommodating a customer request for separate electric and gas ESCOs, and the lack of 24-7 call centers at some ESCOs (see Matters, 7/8/09).

Mass. Suppliers Say Proposed Referral Program Fails to Meet Statutory Requirements

Massachusetts competitive electric suppliers intend to file alternative terms and conditions to govern a supplier referral program by July 27, arguing that a model proposal developed by the distribution utilities fails to meet statutory mandates for the referral program.

As only reported by *Matters*, the utilities' model terms and conditions would simply provide customers with a list of electric suppliers, and would not present customers with specific offers from suppliers as part of the referral program (Matters, 7/15/09).

Statute plainly requires the utilities to, "describe then available offers," as part of the referral program, RESA said, arguing that Section 60 of the Green Communities Act, "states unequivocally that the EDCs [electric distribution companies] must play an active role in informing customers about their options for competitive supply."

RESA intends to file an alternate model program by July 27, and said it would collaborate with other suppliers in developing its proposal. RESA said that its proposal will adopt many of the key features of Connecticut's referral program, including:

• Standardizing the types of offers that competitive electricity suppliers may post to the referral program;

• Use of interactive voice recording (IVR) systems to describe the customer's utility rate, followed by a description of competitive supply offers in ascending price order (lowest price first);

• Allowing a customer who is interested in a particular competitive supply offer to be transferred through the IVR to a call center operated by that supplier; and

• Inserting lists of qualifying electric suppliers (also in ascending price order) in customer utility bills on a quarterly basis.

Dominion Retail agreed that the utilities' proposal does not comply with the statute and suggested similar modifications. In particular, Dominion Retail agreed that supplier offers through the referral program should have the same terms and conditions, and said bill inserts should be sent out quarterly or at least twice annually. Referral program bill inserts should also include an enrollment option for customers, Dominion Retail said.

Nstar, however, maintained that suppliers should retain the full responsibility for articulating specific prices and terms to potential customers. "Placing too great a role upon the [distribution] Companies to serve as 'middlemen' information repositories for competitive supply options may ultimately lead to customer confusion and may adversely, and unfairly, impose service quality challenges for the Companies," Nstar said.

Nstar said an "offer" articulated by the utility through its call center, bill messages or bill inserts that includes specific price terms may be perceived in many instances by customers as a legally binding commercial transaction, to the extent such offer is ultimately accepted by customers. Nstar also raised concerns about, "bait-and-switch tactics used by some less-reputable competitive suppliers in other jurisdictions."

"Under such a scenario, and without any ability to buffer NSTAR Electric from the actions and offers of the competitive suppliers over which the Company has no authority, any customer disenchantment with the competitive supply experience could easily result in increased call volumes to NSTAR Electric to address issues beyond its control, customer frustration, and ultimately increased service quality implications as frustrated consumers turn to the Department to resolve their complaints," Nstar said.

RESA, however, noted that standardizing the referral program product, as done in Connecticut, would mitigate any concerns about costumer confusion or apples-to-apples comparisons. In contrast, the utilities' recommendation of merely listing eligible suppliers, each using multiple offers (e.g., variable, six month fixed, 12 month fixed) can lead to customer confusion, RESA said.

The features of the standard referral product may be set by the DPU, RESA added, noting Connecticut requires a 12-month fixed product with no termination fees to eliminate the potential for bait-and-switch.

The Attorney General argued that it, "may not be feasible," to plainly distinguish for customers that suppliers are responsible for the accuracy of the content of an offer presented by the utility in a referral program.

The utilities' proposed model terms and conditions would recover incremental costs of the referral program from suppliers. Nstar said it will incur additional costs for, among other things: (1) customer service staffing and training; (2) hiring additional staff to manage the program; (3) time required to participate in working groups to develop and implement the program offerings; (4) the development, printing and mailing of bill inserts and bill messages; and (5) other costs. The Associated Industries of Massachusetts agreed customers should not bear implementation costs in base rates or delivery surcharges.

While willing to shoulder program costs, Dominion Retail said various safeguards are needed with respect to the tracking and recording of implementation costs by utilities.

Dominion Retail also said that the current provision requiring mass market customers leaving fixed-price basic service to be rebilled, retroactively, using the monthly variable basic service rate should be eliminated as part of the referral program.

The Cape Light Compact urged the DPU to ensure that the referral program does not have any unintended negative consequences on the automatic enrollment of new customer accounts in the Compact's aggregation program.

AEP Ohio Customers on Discounted Rates May Not Participate in PJM Load Response Programs

Customers at the AEP Ohio utilities taking service under a reasonable arrangement, economic development rider, or other special or discount tariff are prohibited from participating in PJM's demand response programs until the Public Utilities Commission of Ohio decides otherwise in a subsequent order, PUCO ruled in a rehearing order on the AEP companies' electric security plan.

The AEP utilities had asked PUCO to prohibit all Standard Service Offer customers from participating in PJM load response programs. The Commission was not convinced that an abrupt change barring all Standard Service Offer customers from the PJM programs would not harm customers already registered to participate in PJM's programs, given that customers may have entered into contractual arrangements, invested in new equipment, and agreed to operational commitments in reliance on the Commission's initial order.

However, in consideration of the need to balance the potential benefits to PJM load response participants and the costs to AEP-Ohio ratepayers, customers under reasonable arrangements with AEP-Ohio, including, but not limited to, Energy Efficiency/Economic Development Rider, economic development arrangements, unique arrangements, and other special tariff schedules that offer service discounts from the applicable tariff rates, are prohibited from also participating in PJM demand response programs, unless and until the Commission rules otherwise.

PUCO said it requires additional information to consider the costs incurred by various customers, to balance the interest of AEP-Ohio customers participating in PJM's demand response programs and the cost that AEP-Ohio's other customers incur via the companies' retail rates. PUCO said it will reconsider its decision in a subsequent proceeding.

The Commission also affirmed its decision regarding the phase-in of authorized increases to customers' generation rates during the security plan, and said that to the extent that its intended mitigation has not been effectuated through tariffs, it grants clarification. For Columbus Southern Power customers, annual generation increases are capped at 7 percent in 2009 and 6 percent in 2010 and 2011. Ohio Power customers' generation increases are capped at 8 percent in 2009, 7 percent in 2010 and 8 percent in 2011.

In particular, PUCO noted that the AEP companies inappropriately included in the total allowable revenue increase an amount that equals the revenue shortfall associated with their joint service territory customer, Ormet, which raised generation rates above the caps set by PUCO. In their calculation, the AEP companies assumed that the joint service territory customer would continue paying the amount that it was paying on December 31, 2008 (established pursuant to a prior settlement), which was above the approved tariff rate for that rate schedule. Instead, the companies should have calculated the allowable total revenue increase based on that customer paying the December 31, 2008, approved tariff rate for its rate schedule, PUCO said.

Additionally, the AEP companies' allowable total revenue increase should have been levelized, and should not have reflected variations in customer bills for tariff or voltage adjustments, PUCO said, with AEP's approach also resulting in generation rates higher than intended by PUCO.

The Commission denied rehearing on the amount of revenue that the AEP utilities may collect to compensate them for POLR risk. The POLR charges are bypassable for competitive supply customers who agree that any return to the utility would be at a market-based rate. PUCO rejected a request from several industrials to waive the POLR fees for customers who make a contractual commitment not to shop during the term of the electric security plan.

On rehearing, PUCO disallowed recovery of costs associated with maintaining and operating the Waterford Energy Center and the Darby Electric Generating Station facilities through the non-FAC (Fuel Adjustment Clause) portion of the generation rate. The AEP companies have not demonstrated that their current revenue is inadequate to cover the costs associated with the generating facilities, and that those costs should be recoverable through the non-FAC portion of the generation rate from Ohio customers, PUCO said. The AEP companies were directed to remove the annual recovery of $51 million of expenses, including associated carrying charges related to those generation facilities.

Retailers Call Calif. Indicative Resource Plans Incompatible with Direct Access

A California PUC Staff proposal calling for the use of "indicative" resource plans by the state's utilities, "virtually ignores" the question of "bundled versus system" load and the presence of direct access in the state's electric industry, the Alliance for Retail Energy Markets said in comments (R. 08-02-007).

As only reported in *Matters*, the Staff strawman justifies integrated resource planning because new generation is primarily being financed by ratepayer-backed long-term contracts (Matters, 7/2/09). While most aspects of the plans would only be indicative and non-binding, the Commission's approval of an indicative plan would, however, give the utility authorization to procure (build, contract for, or otherwise cause to be constructed) new resources to meet system and/or local Resource Adequacy requirements.

In various prior proceedings, AReM has called for a distinction in new load attributed to growth in bundled customers only, versus the entire system, with different cost allocation mechanisms for related generation applicable under each scenario (i.e. bundled customers should bear the entire cost for growth in bundled load).

Staff's strawman does not address this issue, AReM noted, asking Staff to explain how pre-authorization for the utilities to procure new resources to meet system or local Resource Adequacy requirements could then later be attributed to meeting bundled customers' needs with all associated costs allocated to bundled customers, as may be required in Phase II of the PUC's proceeding.

Furthermore, in Track 2 of Rulemaking 05-12-013, the Commission is considering an "opt-out" by load serving entities from the cost allocation mechanism in Decision 06-07-029 for Resource Adequacy capacity procured by utilities. AReM asked how an LSE opt-out would work under the strawman.

AReM requested that Staff explain how procurement by electric service providers from new generating resources to meet RPS energy or Resource Adequacy capacity requirements can (a) be included in the indicative resource plan and billed to bundled customers, and (b) qualify for the LSE opt-out mechanism being considered in R. 05-12-013.

The Western Power Trading Forum agreed that pre-approval of utility-owned generation as contemplated under the strawman, "totally undercuts and conflicts with," existing Commission precedent.

WPTF said it was "baffled" by Staff's evident return to command and control system planning and associated risks (including stranded costs). The use of such centralized planning, "provides a lack of accountability in that flawed decision-making gets a 'free pass' if it is done in accordance with the immutable 'System Plan,'" WPTF said.

WPTF also said that the indicative plans are unnecessary given the multitude of similar programs in the state, including the Resource Adequacy program which has established capacity counting rules to meet specific reliability thresholds (expressed through the planning reserve margin) considering all the demand and supply side resources.

Furthermore, Staff's strawman fails to discuss the issue of a centralized capacity market, long considered in the state, which would achieve the same objectives as the indicative plans, WPTF said.

Southern California Edison said that if the Commission intends to rely on utility procurement of system resources, rather than quickly establishing an ongoing program to ensure construction of adequate system resources by all load serving entities (such as by adopting a forward capacity market obligation), the PUC will need to ensure that a decision is released in time to conduct a solicitation for new resources in advance of need.

SCE and San Diego Gas & Electric suggested that the Commission's Energy Division assume responsibility for conducting the system-wide policy analyses set forth in the Staff strawman, rather than utilities conducting the planning.

Furthermore, the separate system-wide policy analysis, "should be conducted with the support of outside consultants hired by Energy Division and funded by all customers, not just bundled customers, on a system-wide basis," SCE and SDG&E said.

"Forcing the IOUs to conduct the system-wide policy analyses as part of their Long-Term planning process is likely to foster several misimpressions, including the misimpression that the IOUs seek to usurp the planning functions of third parties and the misimpression that the IOUs alone are responsible for meeting the needs of the system," SCE and SDG&E added.

Addressing the strawman's requirement for granular locational needs analyses, the California Large Energy Consumers Association said it is not clear how utilities could specify the locations of needed resources without pre-judging the results of future supply solicitations. Any preference toward development of resources in certain locations could increase the market power of developers in those areas, the large customers said.

Pacific Gas & Electric also questioned how the indicative plans could provide locational granularity on needs without picking winners.

Briefly:

Nexen Reviewing Options, Including Sale, for Marketing Business

Nexen announced a strategic review of alternatives for its natural gas and power marketing businesses, which may include the sale of all or part of the businesses. Nexen has retained an undisclosed advisor, but said that the review will not impact the portion of its marketing operations dedicated to obtaining competitive pricing for its gas production. Nexen has over 1,600 electricity and natural gas customers in Alberta, and recently acquired Canadian customers of Constellation NewEnergy. Nexen's natural gas marketing business ranks among the top 10 in North America, marketing more than 6 bcf/day. Nexen also manages over 50 billion bcf of gas storage throughout North America.

Glacial Energy Receives Pa. License

Glacial Energy received an electric supplier license from the Pennsylvania PUC to serve all sizes of non-residential customers in all service territories (Matters, 6/22/09).

Premier Energy Group Receives Pa. Broker License

The Pennsylvania PUC awarded an electric broker/marketer license to Premier Energy Group, to broker all sizes of commercial and industrial customers at PPL, PECO, Duquesne, and the three FirstEnergy utilities (Matters, 4/14/09).

Energy New England Seeks Conn. Aggregation License

Energy New England, LLC applied for an electric aggregator certificate at the Connecticut DPUC to pool all classes of customers. Energy New England intends to offer aggregation services to affinity groups, associations, and cooperatives on an as requested basis. Aside from retail supply procurement, Energy New England manages over 700 MW of load, 500 MW of generation and $300 million in structured transactions annually as a wholesale market consultant to munis, independent power producers, and cogenerators.

Pa. PUC Approves Opt-In PPL Mitigation Plan

The Pennsylvania PUC adopted a competitively neutral rate mitigation plan at PPL, that would limit rate increases upon the expiration of rate caps to an average of 25% in 2010 and 25% in 2011 for residential and small commercial and industrial customers (Only in Matters, 6/18/09). The mitigation plan is an opt-in program, and open to customers on default service and competitive supply. The mitigation credit will appear as a line-item on bills, and not affect the price to compare. The Commission adopted a motion from Vice Chairman Tyrone Christy and directed PPL to track and report on uncollectible expenses associated with deferrals under the mitigation plan.

PUCT Staff Opposes OPC Push for 50-50 Debt/Equity Ratio in Nodal Funding

PUCT Staff opposed a recommendation by the Office of Public Utility Counsel to increase equity funding of the nodal project to 50%, instead of the proposed 60/40 debt-to-equity ratio. "Because the cost of debt financing is less than the cost of equity financing, the market benefits from a larger portion of debt financing," Staff said in testimony, noting that the 60/40 ratio is consistent with Commission precedent. Staff noted OPC's recommendation results in a Nodal Surcharge of $0.517 per MWh (if the interim surcharge is adopted) or $0.53 (if the interim surcharge is not adopted). If the Commission adopts a Nodal Surcharge of $0.53, the Nodal Surcharge will increase 214%, Staff noted. ERCOT is requesting a revised surcharge that ranges from $0.335 to $0.375 per MWh, contingent upon the timing and approval of an interim surcharge.

Ameren Energy Resources Reduces Staff

Ameren Energy Resources, which includes merchant generation and energy marketing, announced staff reductions associated with the reduction of 55 positions in response to rising environmental compliance costs and "tough economic and power market conditions." Affected employees are in Ameren Energy Resources' Generation Technical Services group. Ameren Energy Resources also said it is reducing its capital-intensive projects, given the high cost of financing those projects in the current credit-constrained financial markets.

First Choice Power Waives Deposits for Customers Over 62

First Choice Power said that deposit waivers are now available for seniors 62 and older, in announcing several expanded energy assistance measures including additional grants and donations to assistance programs and non-profits. First Choice also said that all residential customers may pay their deposit in two equal installments, as opposed to only qualified low-income customers under the Substantive Rules.

Usource Sales Margin Grows

Unitil reported that the sales margin for broker Usource for the quarter ending June 30, 2009, was up at $1.1 million from $800,000 a year ago.

Monmouth REC Auction Produces Low Price

Evolution Markets Inc. said a June 22 auction to sell RECs generated by the County of Monmouth, New Jersey, resulted in a clearing price of $3.25. Evolution Markets did not disclose the sole winning bidder or four other auction participants vying for the single lot of 6,772 New Jersey Class I RECs. Evolution Markets said that the low clearing price indicates LSEs believe there is an ample supply of RECs for compliance.

Canadian Hydro Urges Rejection of TransAlta Offer

Canadian Hydro Developers' directors recommended that shareholders reject an unsolicited $654 million (Canadian) acquisition offer by TransAlta Corp., saying the offer undervalues the company (Matters, 7/21/09).

Billing Terms ... *from 1*

(C) Monthly charge - any charge, other than a tax or other fee or a transmission and distribution service charge that is assessed on a monthly basis without regard to the customer's demand or energy consumption;

(D) Transmission and distribution charge - any charge that is assessed to recover solely the charges assessed by a transmission and distribution utility (TDU) for the delivery of electricity to customer over poles and wires and other TDU facilities; and

(E) Taxes and other fees - any charge that is assessed to recover taxes or fees assessed by a unit of government in connection with the provision of service to the customer.

Additionally, REPs may use the following terms on their bills if applicable (and may not use alternate terms to describe a charge defined below):

(A) Advanced metering charge - A charge assessed to recover a TDU's charges for Advanced Metering Systems, to the extent that they are not recovered in a TDU's standard metering charge.

(B) Competition Transition Charge - A charge assessed to recover a TDU's charges for non-securitized costs associated with the transition to competition.

(C) Energy Efficiency Cost Recovery Factor - A charge assessed to recover a TDU's charges for energy efficiency programs, to the extent that the TDU charge is a separate charge exclusively for that purpose that is approved by the Commission.

(D) Late Payment Penalty - A charge assessed in accordance with § 25.480 of the Substantive Rules (relating to bill payment and adjustments) for a late payment.

(E) Meter Charge - A charge assessed to recover a TDU's charges for metering a customer's consumption, to the extent that the TDU charge is a separate charge exclusively for that purpose that is approved by the Commission.

(F) Meter re-read charge - A charge assessed to recover a TDU's charges for a customer-requested meter read.

(G) Miscellaneous Gross Receipts Tax - A fee assessed to recover the miscellaneous gross receipts tax imposed on retail electric providers operating in an incorporated city or town having a population of more than 1000.

(H) Nuclear Decommissioning Fee - A charge assessed to recover a TDU's charges for decommissioning of nuclear generating sites.

(I) PUC Assessment - A fee assessed to recover the statutory fee for administering the Public Utility Regulatory Act.

(J) Sales tax - Sales tax collected by a customer's city.

(K) Transition Charge(s) - A charge assessed to recover a TDU's charges for securitized costs associated with the transition to competition.

The definitions of such terms must be easily located on the REP's website.

Staff's draft would also require that REPs, on the first page of the bill in at least 12-point font, include the phrase, "for more information about residential electric service please visit www.powertochoose.com."