Energy Choice Matters

October 9, 2009

CenterPoint Implements Interim Tampering Policy, PUCT Sets Date for Tampering Session

CenterPoint Energy is implementing a new, interim back-billing policy to govern meter tampering, effective yesterday, until the PUCT completes its investigation into tampering issues in Project No. 37291 (Only in Matters, 10/7/09).

Under the interim policy:

- Back-billing will be limited to a period of not more than 18 months
- Billing will be limited to the current REP of Record, or the previous REP if the current REP of Record has been the REP for less than 30 days

The interim back-billing limit will remain in effect until a final rule in Project No. 37291 goes into effect, or September 30, 2011, whichever is earlier.

Additionally, CenterPoint is implementing a new process for providing meter tampering and diversion evidence to REPs. Effective immediately, Competitive Retailers should direct their requests for evidence and other correspondence concerning tampering and diversion to the following e-mail box: ManagingEffortsTowardEnergyRecovery@CenterPointEnergy.com

CenterPoint will respond to requests for evidence with documentation of the tampering/diversion, including the diversion report, affidavit, photographs (if applicable), and a listing of physical evidence retained by CenterPoint. REPs will ordinarily receive a timely reply within fifteen business days; however, collection of evidence materials from some of the TDU's outlying Service Centers may take a slightly longer time to process.

On a related front, the PUCT confirmed that it will hold a special open meeting on November 6 to

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BGE, Columbia File POR Plans, WGL Files for Proration

Baltimore Gas & Electric and Columbia Gas of Maryland filed compliance plans to implement Purchase of Receivables, at a discount, as a result of new COMAR 20.59 (RM 35), while Washington Gas Light has opted to prorate partial payments between supply and delivery charges rather than offer POR.

BGE proposed to purchase gas commodity receivables at a discount reflecting supplier uncollectible expenses, credit and collection expenses, operational costs of POR and other aspects of COMAR 20.59, and a risk component of 1.25% to compensate BGE for the risk associated with the continuation of the supplier-customer relationship. The discount rate would be reconciled annually. Implementation costs would continue to be recovered under the Gas Choice and Reliability Charge (GCRC).

POR would commence with the April 2010 billing, coincident with the start of electric POR (pending Commission approval). A pro forma discount rate was not provided. After the initial rate is set, BGE would file the calculation of the discount rate with the PSC by December 31 of each year with the revised percents to be effective with the purchase of receivables beginning in February of the following year pending Commission approval.

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PPL Says 2010 Residential Rates to Rise 30% After Final Procurement

Rates for residential customers on default service at PPL will increase 29.7% when rate caps expire January 1, 2010, PPL said as it completed its final solicitation for default service power.

While the sixth and final procurement recently completed by PPL produced a residential price of 8.20¢/kWh, the price was blended with the results of prior solicitations laddered over three years, resulting in an average residential price of 9.948¢/kWh, or a 29.7% increase. The laddering was meant to mitigate the price increase seen by customers upon the expiration of rate caps, but actually resulted in PPL locking-in more expensive power from 2007 and 2008 versus what is available had the procurements been more market reflective.

The blended rate for small commercial and industrial customers from all procurements is 10.053¢/kWh, or an 18.4% increase for small businesses and a 36.1% increase for mid-size businesses. The rate from the sixth procurement for these small non-residential customers was 8.399¢/kWh.

PPL said that final retail rates will not be available until December when several smaller components of the bill are routinely adjusted and approved by the PUC. PPL said that the adjustments generally have a minimal effect on customer bills.

PPL also announced the rates for the transitional fixed-price option available for large commercial and industrial customers, who will default to hourly pricing but may elect the fixed utility rate. Customers on rate schedule LP-4 may receive a 9.2¢/kWh fixed rate, and customers on rate schedule LP-5 or LP-6 may receive an 8.95¢/kWh fixed rate. Customers who have expressed interest in the fixed price option earlier in the year will have until November 9 to opt onto the tariff or remain on hourly pricing, if the customer remains on bundled service.

PPL said that 17 bidders participated in the sixth procurement.

Maine PUC Orders CMP, BHE to Enter into Long-Term Supply Contract

Over the objections of Central Maine Power, the Maine PUC ordered CMP and Bangor Hydro-Electric to sign a 20-year contract for bundled energy and capacity with the 60-MW Rollins Wind Project, owned by First Wind Holding. The long-term contract is the first such bilateral procurement ordered by the PUC since receiving statutory authority to permit such long-term PPAs (2008-104, Only in Matters, 7/21/09).

CMP is to purchase 80% of the project's output, and BHE is to purchase the remaining 20%. The Commission said that it will address disposition of the contracted resources in a future order, consistent with statute and rule. The PUC's rule gives it discretion to direct the utilities to:

A. Dispose of capacity resources and associated energy through periodic competitive auctions supervised by the Commission;

B. Use capacity resources and associated energy to meet the supply requirements of Maine ratepayers; or

C. Take other action relative to capacity resources and associated energy as determined by Commission rule or order.

The 20-year contract for energy and capacity is to begin with commercial operation, expected in 2011.

The energy under the contract is priced at the hourly real time locational marginal price at the ISO-NE internal hub (hub LMP) minus $10/MWh when the hourly real time locational marginal price for energy for the applicable node (node LMP) is within 10% of the hub LMP, and hub LMP minus $15/MWh when the node LMP is more than 10% lower than the hub LMP. Because the value of the energy under the contract will reflect the node LMP applicable to the Rollins facility, the two-tiered formula structure is intended to mitigate the risk of divergence between the node LMP and the hub LMP. Due to congestion and line losses, the node LMP has tended to be lower than the hub LMP, creating a risk that the $10/MWh discount off the hub LMP will be higher than the value of the energy. It is for this reason that the discount off hub LMP drops to $15/MWh if the differential between the hub LMP and nodal LMP is greater than 10%, the PUC said.

The energy price has an hourly floor of $55/MWh in the first year that escalates by $1/MWh per year until it reaches $65/MWh in the eleventh year and remains at the level through the remaining years in the term. The contract also has an hourly energy price cap of $110/MWh.

The capacity component of the contract is a financial transaction in which the utility, essentially, obtains the capacity value of the facility for no additional cost above the energy costs. The capacity value is firm in that First Wind must provide it under the contract regardless of how the capacity from the Rollins facility actually fares in the regional capacity market. "This is a key feature of the contract because, although [First Wind] expects that the Rollins project will in the future realize capacity value in the ISO-NE Forward Capacity Market (FCM), the facility is not currently qualified to participate in the Forward Capacity Auction (FCA)," the Commission said.

CMP had recommended that the PUC not require the utilities execute the contract, while BHE also raised several concerns with the contract's provisions.

CMP said that its analysis of the contract over the first ten years of the term shows that the proposal would produce a net cost to ratepayers of several hundred thousand dollars per year over the first five years and a net present value loss of over $1.5 million for the 10-year period (assuming CMP contracts for the entire output of the facility).

The PUC, however, said that the analyses prepared by Staff and its consultant show that the contracts will likely have a small benefit in the early years of the contract that grows over time as electricity and capacity prices are forecast to increase. "These benefits are likely to continue to increase in the outer years of the contract given the trajectory of projected wholesale prices," the PUC said.

"At the outset, we note our agreement with the utilities that there is an inherent risk to long-term contracts in that their economics depend on future projections of energy and capacity prices and, in the case of the proposed contracts, the economics are sensitive to the assumed differential between the node LMPs and the hub LMPs. It is for this reason that we take into account both quantitative economic analyses (including sensitivity analyses), as well as more qualitative considerations," the Commission added.

"Maine's ratepayers are generally at risk of high and volatile market prices. Because the contracts contain a firm price ceiling of $110/MWh, they provide a hedge against high and volatile prices over their 20 year term. We acknowledge that the contracts will have lower or negative benefits if future prices turn out to be lower than expected. However, the potential cost of the hedge is relatively low in that the contracts are small relative to the size of the utilities. In the event that market prices are lower than the expected, any costs of the contracts will occur in an environment of generally lower prices, thus reducing the impact of the contracts on ratepayers," the Commission added.

The utilities had also objected to the asymmetric credit provisions in the contract, which only require First Wind to deliver to CMP/BHE a second lien on the facility. First Wind may also replace the lien at any time with cash or a letter of credit in the amount of $4 million, but the utilities must post $8 million if they fall below investment grade. The utilities argued that the $4 million credit support is inadequate relative to the long term of the contract, possibly allowing First Wind to take advantage of favorable economics in the first few years, but then decide to abandon the contract if market prices rise so that performance is no longer attractive. Moreover, the utilities stated that a second lien is not standard in the industry, is difficult to quantify, and is much less desirable than a liquid asset in securing the obligation.

While the Commission agreed that a second lien is less desirable than more liquid security, the PUC said that, "letters of credit are difficult to obtain and are very expensive in the current financial environment, especially for wind projects and [we] conclude that this security provision does not warrant rejecting the contracts."

The long-term contract statute typically permits PPAs up to 10 years, unless the

Commission finds a longer contract would be in the public interest. The PUC concluded as such in approving the 20-year term for the First Wind contract.

First Wind, "has represented that the contracts are necessary for the projects to obtain financing and, as such, these contracts are necessary for the construction of the Rollins facility. Thus, these contracts will result in new generating capacity being built in Maine, helping to contribute to lower capacity prices within the State and increase the diversity of the resource mix in the State and in the region," the PUC said.

Commenting on the 2006 statute authorizing long-term contracts, the Commission's order explained:

"The underlying purpose of this authority, in the Commission's view, is to take advantage of opportunities to use long-term contracts for capacity and energy with utilities as a means to lower capacity and energy costs or otherwise benefit Maine ratepayers. A long-term contract with a creditworthy counterparty such as a utility can be very valuable to developers or owners of generation resources and may be necessary to obtain financing for new projects. This is especially the case in the current financial climate. Accordingly, project developers and owners may be willing to offer utilities contractual terms that would be beneficial to electricity ratepayers. For example, project developers or owners may be willing to sell capacity and energy at a discount off of expected future prices. Such contracts may also provide a low-cost hedge against rising electricity prices (resulting from increases in natural gas prices). Moreover, by allowing for financing of projects and subsequent development that might not otherwise occur, long-term contracts could facilitate the construction of generation facilities in Maine. Such new generation could serve to lower capacity costs in Maine, enhance reliability, and promote the State's renewable energy development policies," the PUC said.

Pa. PUC Orders Columbia to Inform Customers that Future Shopping Will Not Affect Supply Refund

The Pennsylvania PUC approved a request from Columbia Gas to accelerate the refund of overcollections of gas commodity costs, but ordered Columbia to inform customers more explicitly that customers eligible for the refunds will remain eligible even if they subsequently choose a competitive gas supplier.

The nearly $78 million in refunds will be provided to customers who were on sales service any time between Oct. 1, 2008, and Sept. 30, 2009, based on their usage in that period. Customers on competitive supply during that entire period are not eligible for the refund, since they did not contribute to the overcollection, and customers who switched to or from competitive supply will only be eligible to the extent of their sales service consumption.

According to Columbia, the overcollection resulted from a large, sustained reduction in natural gas prices, which occurred after Columbia had filed its quarterly adjustment.

The eligible customers will receive a one-time credit on their bills during the November 2009 billing cycle. If the credit exceeds the customer's balance, the difference will carry over into the next billing cycle or the customer may request a check for the difference.

Columbia stated that the credit will not affect any customer's decision to purchase gas supply from a competitive supplier. The refund will not affect the price to compare but will instead appear as a line item bill credit. Additionally, since the credit is based upon past period sales volumes, a customer's future decision to switch to an alternative supplier will not affect their right to the receive the refund.

However, the Commission agreed with the Office of Small Business Advocate that, in order to remove any ambiguity, a bill insert regarding the credit should clearly state that customers will still get their refund even if they decide to shop.

The Commission also directed Columbia to prepare a detailed evaluation of its gas price forecasting and cost accounting procedures, to determine the detailed causes for the current over-recovery problem.

PUCT to Allow Leases to Offset Some of CREZ Deposit

The PUCT will allow renewable energy developers to offset a portion of any required Competitive Renewable Energy Zone deposit with land leases they have for a particular project, under a final rule approved by the Commission yesterday (34577, Only in Matters, 10/2/09).

The Commission maintained a requirement for a deposit in the amount of $15,350/MW, as proposed by Staff, if the Panhandle CREZs cannot show evidence of financial commitment through either (1) the capacity of installed generation located in the counties contained in whole or in part in a CREZ; (2) generation under construction that will be online within six months; or (3) generation with signed interconnection agreements.

However, the deposit amount could be lowered to $10,000/MW if the developer can show a financial commitment under a lease for its project. Commissioner Donna Nelson brokered the accommodation for leases because, among several reasons, she believes collateral will not be any better in predicting future development, because suppliers will not invest billions of dollars in a project whose economics no longer justify development simply to recover millions in collateral. Collateral will simply tie up money and raise costs for developers, Nelson said.

The Commission also adopted a change offered by Commissioner Kenneth Anderson to require that deposits must be only posted for 50% of the CREZ's capacity (in combination with any other financial metrics), rather than 100%, to show evidence of financial commitment.

Collateral must be posted within 30 days of an order approving the filing of CCNs, rather than 15 days as in the draft.

Under the final rule, collateral will be returned to the developer upon the developer posting a deposit required for an interconnection agreement, rather than when then developer simply signs an interconnection agreement (as in the draft), or when the developer takes service under the transmission line (as in the former rule).

Otherwise, there were no substantive changes to Staff's draft proposal, which found that the three southern CREZs and the default and priority lines do not require any additional showing of financial commitment.

Briefly:

Major Energy Services Receives Pa. Gas License

The Pennsylvania PUC granted Major Energy Services a natural gas broker/marketer license to serve all customer classes at Columbia Gas and National Fuel Gas Distribution Corporation (Only in Matters, 8/7/09).

Energy Cooperative Of New York Receives Pa. License

The Pennsylvania PUC granted the Energy Cooperative Of New York an electric broker/marketer/aggregator license to serve all sizes of commercial, industrial and governmental customers at PPL (Only in Matters, 8/19/09).

Co-exprise Seeks Ohio License

Co-exprise filed for an Ohio electric broker/aggregator license to serve commercial, mercantile, and industrial customers in all service areas.

Amerex Receives Texas Aggregation License

The PUCT granted Amerex Brokers LLC an aggregator certificate, reflecting the LLC's purchase of the assets of Amerex Retail Energy Services, Ltd, which had held a certificate.

Md. PSC Denies Electric License for SourceOne

The Maryland PSC denied the electric supplier application of SourceOne, Inc for a deficient filing and failure to respond to Staff's RFI.

Pa. PUC Says TOU Orders Must Come Within Six Months of Filing

The Pennsylvania PUC ruled yesterday that statute requires it to address electric distribution utilities' Time of Use rate filings within six months of their filing at the Commission. Specifically, the PUC found that it must complete its investigation on PPL's proposed time of use program by Jan. 31, 2010, reflecting PPL's July 31, 2009 filing date. The Office of

Trial Staff had interpreted statute as allowing the Commission six months from the TOU tariff's effective date to complete its investigation (which in PPL's case would be July 1, 2010 based on a proposed effective date of January 1, 2010), but the Commission disagreed.

PECO Launches Solar REC Procurement
PECO launched its competitive solicitation to procure 80,000 solar alternative energy credits, as recently approved by the Pennsylvania PUC (Matters, 8/28/09). Through a competitive RFP, PECO will enter into fixed-price agreements with winning bidders to purchase up to a total of 8,000 credits per year for 10 years. PECO expects to enter into the agreements by February 2010, for delivery beginning immediately for existing projects or up to a year for projects under development. PECO scheduled a bidder teleconference for Oct. 22.

Tampering ... from 1

address meter tampering issues. The meeting will function as a workshop but will be noticed as an open meeting so all three Commissioners may attend.

Among issues to be addressed are potential standards to define tampering, standards for how far back a TDU can charge a REP for delivery, whether the customer should lose power for tampering, and what evidence is required.

Commissioner Donna Nelson noted that the burden of proof seems to be on the REP under the current rules. Chairman Barry Smitherman said he's not sure such an assignment is right.

At Nelson's suggestion, the Commission will endeavor to bring district attorneys to the open meeting, as Nelson noted meter tampering often involves theft valued well in excess of shoplifting cases which are prosecuted. The DA's, which have generally been reluctant to prosecute meter tampering, can also provide insight on what level of evidence should be required in the rule.

Smitherman again cited the urgency to get something done, stating that he was "astounded" by recent tampering numbers reported by the TDUs.

Md. POR ... from 1

Only commodity costs would be purchased, and BGE would not purchase any receivables billed prior to April 2010. Any supplier customer served on utility consolidated billing would be required to participate in POR. However, suppliers could still opt to dual bill specific customers while leaving other customers in the utility consolidated billing/POR program.

BGE would pay all undisputed charges by the fifth day from the due date noted on the bill. The gas supplier's receivables would be purchased on a non-recourse basis and BGE would not return the customer to provider of last resort service or require a gas supplier to switch the customer to dual billing if a customer fails to pay the gas supplier's charges. However, in the event that a customer disputes a gas supplier's charges and notifies BGE, the utility can reverse the disputed amount if paid to the supplier, and stop payment to that gas supplier for that individual account until such time that BGE is notified that the dispute has been resolved. Once resolved, BGE will remit the payments withheld from the supplier during the dispute period.

BGE said that it can implement many of COMAR 20.59's technical requirements under its current processes, prior to the development of uniform electronic transactions in a working group. The provisions which must await a uniform electronic transaction are the inclusion of the billing address in the pre-enrollment information, and changing the enrollment and drop deadlines to 12 days before the end of the month

Washington Gas Light
WGL was the only utility (including electric utilities) to elect to prorate partial payments among supply and delivery charges rather than implementing POR (excluding Elkton Gas which has asked for a waiver of utility consolidated billing). WGL said that the first phase of its COMAR 20.59 compliance plan would include prorating partial payments, as well as volume proration to make the supplier whole due to the lag between initial delivery and initial billing. Phase I would be completed in Mid-October 2010, WGL said.

Under the partial payment proration, WGL will apply a partial payment to supply and delivery charges equal to the charges' ratio on the total bill. For example, if supply charges account for 70% of the total bill, 70% of any partial payment, regardless of amount, will be applied to supply charges, as opposed to the current payment order which requires all delivery charges to be paid first.

To compensate suppliers for deliveries prior to when billing commences, WGL proposed to credit back to suppliers the calculated volumes for the cycle days that the supplier is not responsible for deliveries due to cycle billing, using one of three options (at the supplier's choice):

1. Reduction in daily required volumes for the following month;
2. Credit to the "accumulated unbilled," or
3. Credit to supplier "balance account."

Phase II of WGL's compliance plan would include development of an electronic transaction system, projected for mid-May 2011, but is dependent on the outcome of the working group.

WGL said that its compliance plan would cost $2.1 million and require 26,000 hours.

WGL proposed to recover through a "Gas Choice Charge" on distribution service various IT and operating costs, as well as any increased levels of bad debt created by the proration of partial payments.

Columbia Gas

Columbia filed to institute Purchase of Receivables with a discount rate reflecting commodity related bad debt, program development and operation costs for POR and other COMAR 20.59 requirements, including credit and collection costs, and the risk associated with the continuation of the supplier-customer relationship. Columbia said such terms conform to the PSC's order in approving POR at Allegheny Power, as only reported in Matters (Only in Matters, 10/7/09). However, as the Commission's decision was only released Tuesday, Columbia said that it has not had time to calculate what percentage the discount rate will be when including all of the stated factors.

Columbia also said that it cannot distinguish commodity-related bad debt among specific rate classes. Purchased receivables would only include commodity costs, Columbia said.

Under Columbia's compliance plan, POR would be implemented in January 2011.

Columbia reserved the right to change the discount rate, or elect to end POR and institute partial payment proration, at its discretion. Columbia said any such change would be limited to once annually, and said suppliers would be provided 60 days notice.

Chesapeake Utilities, Elkton Gas

Only non-residential customers with usage of at least 30,000 Ccf annually may elect transportation service at Chesapeake, so Chesapeake did not file to include various residential provisions of COMAR 20.59 in its compliance plan.

Chesapeake proposed to purchase supplier receivables (commodity only) at a 1% discount, reflecting the uncollectibles cost in its last rate case. Chesapeake would not purchase any receivables billed prior to POR implementation, which is expected in the second quarter of 2010.

Additionally, Chesapeake filed to impose an $8 per customer fee per month to issue a utility consolidated bill.

Chesapeake also filed for approval of a "Supplier Cost Recovery" charge to recover other costs of COMAR 20.59 implementation. Per Chesapeake's compliance filing, the Supplier Cost Recovery charge would only be applied to customers on competitive supply. Chesapeake is not yet seeking a specific amount to recover through the Supplier Cost Recovery charge because some costs, such as implementation of electronic transactions, will not be known until a working group adopts standards.

Chesapeake would remove its current October 1 window for choice enrollment, but its revised tariff would still require choice customers to make a one-year commitment to transportation service.

Chesapeake also sought other changes to its current tariff.

First, Chesapeake proposed that each customer should be required to calculate its respective daily contract quantity (DCQ) of gas and submit it to the LDC. Chesapeake also proposed the implementation of a usage threshold of 50% above or below the sum of the customer's calculated DCQ for a particular month. If and when that threshold is exceeded, above or below, a fee would be assessed that equates to 10% of the imbalance charge for the amount over, or under, utilized by that customer. "The primary reason for this charge is because of the impact that varying customer usage has on the Company's gas sales customers. Chesapeake provides daily balancing for its transportation customers and its ability to provide this service is hindered when customers' usage is not in line with the amount of gas that is being delivered," Chesapeake said.

Chesapeake also proposed that it will no longer calculate the cash-in/cash-out or imbalance rate for transportation customers based on its weighed average cost of gas (WACOG). Chesapeake instead would use the imbalance rate calculated by the Eastern Shore Natural Gas Company, which is the transmission pipeline that directly connects to Chesapeake's distribution system. The new rate is the same that Chesapeake is charged, and Chesapeake thus said that the rate would result in no difference between the imbalance rates Chesapeake incurs and the rates it charges to transportation customers.

As previously reported, Elkton Gas is seeking a waiver of the utility consolidated billing (and associated POR/proration) requirement and first-of-the-month enrollment, citing its small customer base and lack of supplier interest (Only in Matters, 9/15/09). However, if the waiver is denied, Elkton said that it would implement proration rather than POR.