Energy Choice Matters
May 22, 2009

BGE to Implement POR in April 2010; Allegheny in Dec. 2009, Under RM17 Plans

Baltimore Gas & Electric would introduce a non-recourse, non-discounted electric Purchase of Receivables program for the April 2010 billing cycle under an RM17 compliance plan filed with the Maryland PSC.

RM17 mandates that utilities either purchase electric supplier receivables, or pro-rate partial payments between supply and distribution charges. BGE has elected to purchase the competitive power supply receivables of all suppliers using consolidated billing, excluding receivables for charges other than electric supply (i.e. energy audits, sale of energy efficient appliances, appliance repair, etc.).

POR programming will take about 6,200 hours, while total hours to implement RM17 will be 11,000 hours, BGE said. Accordingly, BGE sought to implement POR with the April 2010 billing cycle, with the current partial payment processing order remaining applicable until then. BGE will not purchase any supplier receivables that were incurred prior to the effective date of POR.

Under POR, BGE will pay all undisputed charges by the 5th day after the due date listed on the customer's bill, without any discount or recourse. BGE will not return a customer to Standard Offer Service or require an electricity supplier to switch the customer to dual billing if a customer fails to pay the electricity supplier's charges.

All customers on consolidated billing will be included in the POR program. Although not explicit, BGE's revised coordination tariff permits suppliers to place some customers on dual billing, with such receivables not purchased by BGE, while placing other customers on consolidated billing with

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FERC Approves Participant Funding Approach for Nstar-NU Line to Access Quebec

FERC approved a request for a declaratory order from Nstar and Northeast Utilities that will allow the utilities to proceed with a participant funding approach for a 1,200-MW transmission line into Quebec which will transfer hydropower from Hydro-Quebec TransEnergie into New England (EL09-20, Matters, 1/23/09).

Under the order, the first 1,200 MW of capacity on the line will be reserved for a 20-year PPA to be executed between H.Q. Energy Services, and Nstar and Northeast Utilities. Nstar and NU have said they intend to conduct an open season for 200 additional megawatts, and may pursue such expanded capacity depending on interest.

The declaratory order did not address specific rates, terms and conditions of any transmission service, which will be cost-based and reviewed in a subsequent proceeding.

FERC dismissed concerns regarding undue discrimination raised by merchant generators because transmission owners have an obligation to expand the transmission system if service is requested. The Commission said there were no bundling concerns because the service and rates for transmission and power will be provided under separate agreements, with the rates separately stated. The Commission also found no affiliate abuse concerns.

Although as a participant funded project the line's costs will not be included in transmission rates

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PUCT Denies AEP Oklaunion Appeal

The PUCT, in a 2-1 decision, denied AEP Energy Partners' appeal of the ERCOT congestion zone designations, and the placement of its Oklaunion plant in the West zone, though none of the Commissioners were pleased with how ERCOT handled the development of the zones (Matters, 5/21/09).

Chairman Barry Smitherman and Commissioner Kenneth Anderson ultimately were not prepared to uphold the appeal, in part because of the question of what remedy the Commission should provide going forward -- e.g. adopting a congestion scenario itself, or directing ERCOT to re-perform the process for designating congestion zones. With the process for the designation of 2010 congestion zones set to start in July, ERCOT's ability to complete a reassessment of 2009 zones was a concern.

Although it was a "close question" whether placing Oklaunion in the West zone was arbitrary or discriminatory, Anderson ultimately concluded that ERCOT Staff was acting in good faith, and that Staff must be given latitude.

Commissioners also directed ERCOT to revise its Protocols to improve the congestion zone designation process, including clarifying the procedures for using a limiting element as the Commercially Significant Constraint, and addressing the nondiscriminatory application of a post-contingency clustering analysis. Although the Commission did not adopt specific language for revisions, ERCOT has said it is aware to the Commission's concerns and will rectify them. Smitherman said that the Commission has broad authority under PURA to direct ERCOT to make changes should ERCOT's revisions not be satisfactory.

Commissioner Donna Nelson dissented from the decision, because of the totality of the circumstances in the case. While one anomaly -- either the novel use of a post-contingency analysis, the call among four generators and ERCOT which did not include AEP, or the unusual process for considering Scenario 3i at ERCOT which included a joint WMS-TAC meeting -- could be dismissed, all of them together cannot be ignored, Nelson said. Nelson criticized ERCOT Staff and the four generators for not having the foresight to include AEP, the entity most negatively affected by the new Scenario 3i, in their discussions. Nelson said that in the future, if stakeholders are going to have a meeting that prompts them to follow a certain course of action that will negatively affect a single entity, "they'd better dot their I's and cross their T's."

State Affairs Advances Suspension of Entergy Transition to Competition

The Texas House State Affairs committee reported favorably without amendments SB 1492 which would require the PUCT to cease work on Entergy Texas' transition to competition plan, and require Entergy to withdraw the plan (Matters, 4/29/09).

Under the bill, any party could petition the Commission to initiate a proceeding to certify a qualified power region for the Entergy area when the conditions supporting such a proceeding exist. If the Commission certifies a qualified power region for Entergy, the Commission could not approve a transition to competition plan until at least four years after certifying the qualified power region.

The bill also calls for a competitive generation tariff at Entergy.

Surplus Generation Price Stricken from SB 545

The Texas House Energy Resources committee reported out a substitute version of SB 545 which would primarily establish a solar power customer incentive/rebate program, but also would have originally required REPs to purchase surplus solar generation at fair market value.

The Senate engrossed version of the bill would have compelled REPs to purchase excess distributed solar generation at or above a PUCT-determined fair market value, or, for residential customers only, the real-time price for energy (Matters, 4/22/09).

However, the version of the bill reported out of the House Energy Resources committee strikes all language regarding a surplus generation purchase obligation. The House has addressed the price to be paid surplus renewable generation in HB 1243, which was considered at a Senate hearing today (Matters, 5/18/09).

The House version of SB 545 would generally retain the same incentive payments for solar installations as the engrossed Senate bill, though the rebate classes would be more specifically defined by size rather than customer type. Unless otherwise adjusted by the PUCT, the initial solar rebate amounts under the House bill would be:

(1) $2.40 per watt for installation of distributed renewable generation with a capacity of not more than 10 kilowatts;

(2) $1.50 per watt for installation of distributed renewable generation with a capacity of more than 10 but not more than 2,000 kilowatts; and

(3) $1 per watt for installation of wholesale or industrial generation.

The House's nonbypassable surcharge which would fund the solar program also differs from the Senate version, with the House calling for a fee of:

(A) $0.000650 per kilowatt-hour for each residential or commercial customer meter; and

(B) $40 per month for each industrial customer meter.

FERC Rejects Price Screens Under CAISO Price Cap Tariff

FERC conditionally accepted tariff sheets from the California ISO to implement FERC's Price Cap order, which permits the CAISO to delay posting settlement prices that meet or exceed the price cap and floor until further verification and/or correction, for up to 48 hours (ER09-241).

In the Price Cap order, FERC conditionally accepted CAISO's proposal to adopt a price cap of $2,500 per MWh and a price floor of negative $2,500 per MWh for locational marginal prices, residual unit commitment prices, and ancillary services marginal prices in all Market Redesign and Technology Upgrade (MRTU) markets, in order to prevent severe settlement impacts stemming from extreme prices that could result from the CAISO's transition into the MRTU market.

However, FERC rejected six additional price screens proposed by CAISO, which were opposed by the Western Power Trading Forum. The price screens were to identify prices that, although within the bounds of the price floor and cap, still have a significant chance of revision, due to improper data input, hardware or software failure, or a result that is inconsistent with the CAISO tariff.

"The CAISO has not demonstrated that additional price screens accurately identify prices that are subject to revision and has not justified the price screens and the basis for the price screening thresholds," FERC said.

FERC ordered CAISO to submit a further compliance filing to reflect that CAISO will delay the publication of only those market clearing prices that exceed the price cap and floor.

Briefly:

PUCT to Further Consider Expedited Switching Process

The PUCT deferred adoption of an accelerated customer switching timeline to its next open meeting, mainly to refine language and draft the preamble. Otherwise, Commissioners generally agreed on the process outlined in Chairman Barry Smitherman's revised proposal (Matters, 5/21/09), which would limit estimated reads for switches to residential customers during a transition period. The only substantive issue engendering discussion was Commissioner Kenneth Anderson's concern about draft language which holds that estimated reads during the transition period will only be changed upon agreement of the TDU and one of the REPs. Anderson wants to make sure such language does not preclude the customer from challenging the estimate under other Commission consumer protection rules.

PUCT Maintains 16.9¢ Nodal Fee Through Sept.

The PUCT voted to maintain the current ERCOT nodal implementation surcharge of 16.9¢/MWh through September 2009.

REPs May Ask for Extension of August Audit Deadline

Although the PUCT is not granting a blanket waiver of the new August 15, 2009, deadline for submission of REP audited financial statements, the Commission said REPs may file at that time justification for their inability to meet the deadline, and inform the Commission of when the information will be filed. Staff has raised concerns that REPs may be unable to find available auditors and have audits completed by August 15. Staff also reported a new REP certification form should be available within three weeks, and Staff will also open a project to develop and adopt the standard form agreement to be used under the certification rules within 90 days.

PSEG Energy Wins CL&P Last Resort Service Load

Connecticut Light and Power reported that PSEG Energy Resource & Trade won 100% of the load for Last Resort Service for the period July through September 2009.

FERC Authorizes Exelon Acquisition of NRG Energy

FERC authorized Exelon's hostile acquisition of NRG Energy, finding that Exelon's divestiture proposal mitigates any merger-related harm to competition (EC09-32). While approving the divestiture plan, including with respect to ERCOT generation, FERC said its order does not affect the authority of the PUCT to review the transaction. FERC conditioned its approval on Exelon submitting any change in circumstances that would reflect a departure from the facts the Commission relied upon in its order. In particular, should any state or other regulator modify Exelon's proposed mitigation measures, including ring-fencing, divestiture, or other elements, Exelon must file a copy of that decision with FERC within 10 days of the issuance of that decision.

FERC Staff Monitoring Real-Time Price Spikes in San Diego

FERC Staff has been in daily contact with the California ISO concerning significant intermittent price spikes seen in the San Diego area under the real-time MRTU market. Staff said the spikes indicated technical issues that need to be worked through, rather than any manipulation, and said the ISO is addressing the issues. The day-ahead market is functioning smoothly, Staff said, in presenting a summer market update generally forecasting lower power prices across the U.S.

PUCO Staff Backs Dayton Transmission Rider

Staff of the Public Utilities Commission of Ohio has recommended approving Dayton Power & Light's amended application to recover various costs through a new transmission rider (Matters, 5/19/09). Industrials have opposed the rider for including Reliability Pricing Model-related costs in the rider, which industrials argue are generation-related.

PUCT Defers Action on Kelson CCN

The PUCT deferred consideration of Kelson Transmission's CCN application for its 1,200 MW line to connect the Cottonwood plant to ERCOT until its next open meeting (Matters, 5/8/09).

Duke Energy Acquires 70-MW Gamesa Wind Project

Duke Energy is acquiring the 70-megawatt North Allegheny Windpower Project in Pennsylvania from Gamesa Energy USA. With the acquisition comes a 23.5-year power purchase agreement to sell all of the output from the wind farm and associated renewable energy credits to FirstEnergy. Commercial operations are to begin later this year.

FERC Accepts Reporting Requirements for 33.1(c)(12) Blanket Authorizations

FERC adopted reporting requirements related to the expanded blanket authorization under section 33.1(c)(12) of the Commission's regulations which authorize a public utility to transfer its outstanding voting securities to "any person" if, after the transfer, such person and any of its associate or affiliate companies will own less than 10 percent of the outstanding voting interests of such public utility (RM07-21). The Commission will require public utilities using the blanket authorization to file a report with the Commission listing: (1) names of all parties to the transaction; (2) identification of both the pre-transaction and post-transaction voting security holdings (and the percentage ownership) in the public utility held by the acquirer and its associates or affiliate companies; (3) the date the transaction was consummated; (4) identification of any public utility or holding company affiliates of the parties to the transaction; and (5) a statement on cross-subsidization of the same type as currently required under § 33.2(j)(1) of the Commission's regulations.

FERC Approves ISO-NE ICR

FERC accepted ISO New England's Installed Capacity Requirements for the 2009/2010 Capability Year pursuant to the settlement agreement establishing the Forward Capacity Market, once again dismissing arguments from the Connecticut DPUC that FERC action would encroach upon states' authority over resource adequacy (ER09-864).

FERC to Revoke MBR Authority of Knedergy, Westbank Energy Capital over Delinquent EQRs

FERC said it intends to revoke the market-based rate authority of Knedergy, LLC and Westbank Energy Capital, LLC for failure to file electric quarterly reports, unless the entities submit their reports within 15 days.

Maryland POR ... *from 1*

POR. Such treatment is consistent with (if not compelled by) Maryland regulations which give the customer -- not the supplier -- the right to choose a consolidated or dual bill.

In the event a customer disputes an electricity supplier's charges and notifies BGE, BGE can reverse the disputed amount if paid to the supplier, and stop payment to the supplier for that individual account until BGE is notified that the dispute has been resolved.

BGE has proposed to recover implementation costs, supplier uncollectibles, and a return adder through a nonbypassable surcharge called the Electric Choice Charge (Rider 29).

Recovering uncollectibles though the surcharge, rather than through a discount, "benefits the competitive market because suppliers can establish their prices without incorporating the known discount plus a risk associated with future discount rates required for longer term contracts," BGE said, adding that paying 100% of receivables' face value will make the Maryland market more attractive to suppliers

"BGE anticipates that suppliers would in turn pass this benefit onto its customers, allowing the supplier to offer competitive rates."

If the Commission does not approve the surcharge, BGE alternatively will propose a cost recovery mechanism that involves a discount on receivables.

The "Return Component" of the surcharge would compensate BGE for offering a Purchase of Receivables service.

"BGE will experience a business risk in that the Company's core business is that of a gas and electric utility, and not a financial institution. Because BGE is compelled to operate outside of its core business it should be compensated for the risk associated with this function," BGE argued.

For example, while BGE will remit uncontested receivables to a supplier within five days of the billing due date, BGE only collects 74.7% of its residential electric customer billings in the first 30 days after billing, implying that the proposed approach will not fully mitigate cash working capital needs. The Return Component will help to cover these cash working capital needs, BGE said.

BGE recommended using a Return Component of 0.15 cents/kWh for purchased residential receivables and 0.20 cents/kWh for purchased non-residential receivables consistent with the POLR Settlement Agreements approved in Case No. 8908.

Under the POR program, if an electricity supplier's customer is on budget billing, BGE shall only be obligated to purchase each month the amount of the monthly installment under the budget billing plan. BGE shall add to or deduct from any payments due to an electricity supplier the amounts that may result from reconciliations, adjustments or recalculations of estimated readings, cancel and rebills, or any applicable billing adjustment.

As part of its RM17 compliance plan, BGE will also give electric suppliers online access to customers' 12 most recent bills by August 1, 2009, which is the same information currently available to customers. BGE will modify its Customer Consumption Data website (CDWeb), to provide suppliers with the ability to view these previous bills. BGE will concurrently make modifications to give gas suppliers using BGE's consolidated bill the same electronic access to customer bill information provided to the customer via the CDWeb.

Allegheny

Allegheny Power also chose to implement Purchase of Receivables, rather than pro-rated payments, in a plan nearly identical to BGE's. Allegheny's program would also be non-recourse with no discount, with uncollectibles (and implementation costs) recovered through a nonbypassable Societal Benefits Charge. Allegheny's surcharge would not include a return adder.

Allegheny proposed that POR be effective December 15, 2009.

Specifically, Allegheny said POR would cover, "retail supplier sales of generation and transmission services when the supplier chooses to use utility consolidated billing."

Allegheny also explicitly states that a supplier may continue to use dual billing even when placing some customers on POR, though POR will not be applicable to such dual-billed customers.

Operationally, Allegheny's POR program will function identically to BGE's, with the same payment date, and caveats for disputed charges, customers on budget billing, and various reconciliations.

Implementing POR will cost Allegheny $354,450 and take 4,170 developmental hours to complete.

Both Allegheny and BGE asked the Commission to approve their plans at the June 17 administrative meeting to expedite implementation.

Nstar-NU ... *from 1*

for ISO New England transmission customers, Commissioner Philip Moeller, who supported the order but will write a separate concurrence, asked Staff to explain who will ultimately pay for the line, since someone must. Staff said any party purchasing power from the HQUS PPA will ultimately pay for the line, and FERC will have no information on those rates outside of the electric quarterly reports. Nstar and NU said they have been working with state regulators to ensure that any price for wholesale power from the PPA retailed to their distribution customers is "fair," and the utilities stressed that their customers also have retail choice.

Moeller stated that, "[w]hile some parties to this proceeding argue that the proposed structure of the transmission project conflicts with our open-access and non-discriminatory transmission requirements, the parties have not clearly demonstrated how the Petitioners' request interferes with our existing requirements or Commission policy."

FERC Chairman Jon Wellinghoff said, "the project promotes competition in the region by facilitating the transmission of Canadian hydro power to markets in the United States, enhancing the region's fuel diversity."

Nstar and NU have said that they, "intend that the power sold under the PPA will be made broadly available to load in New England, which would include customers of investor-owned and publicly-owned distribution utilities."