Energy Choice Matters

March 10, 2010

Pepco Asks to Delay POR Compliance Filing Until PSC Adjudicates Delmarva Plan

Pepco petitioned the Maryland PSC to delay the requirement for Pepco to file a revised compliance plan to institute purchase of receivables under COMAR 20.53 until the PSC resolves issues in Delmarva's compliance filing.

Pepco filed its original POR compliance plan some 10 months ago, in May 2009. The PSC took nearly half a year to conclude that the compliance plan was insufficient, and directed Pepco (and contemporaneously the other electric utilities) to file revised compliance plans including POR discount rates so that customers are not allocated implementation and uncollectible costs. While the other three electric distribution companies filed revised plans shortly thereafter, Pepco has not yet responded to the PSC's October 2009 letter order.

In its request for a delay, Pepco said that it expects to file a compliance plan that is substantially similar to the Delmarva compliance plan, and also expects that the derivation of a discount rate should be the same for both companies. Thus Pepco said that it would be more efficient to wait for the outcome of the Delmarva compliance filing before submitting its own filing.

Unlike several of the other utilities, who have had their POR deadlines explicitly waived by the Commission in response to their second (post October order) compliance filings, Pepco has not received such a waiver of the previously ordered deadline of April 1, 2010 for instituting POR (since it never submitted a second compliance filing to prompt further suspension). Indeed, no Commission order has superseded the requirement in the October 7, 2009 letter order that, "the Commission approves the Company's proposed implementation date of April 1, 2010 for its POR Billing System."

The October letter order also said that, "The Commission does not require the Company to

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UGI Files Settlement to Procure SOS for ≤500 kW C&I Customers on One-Year Contracts

UGI Utilities and the Office of Small Business Advocate, joined in part by the Office of Consumer Advocate, filed a settlement which would establish a default service plan for commercial and industrial customers with peak demands of 500 kW or less for the period June 1, 2011 though May 31, 2014 relying on the use of one-year full requirements contracts (P- 2009-2135496).

The Office of Trial Staff and Constellation Energy do not oppose the settlement.

Under the settlement, UGI would conduct semi-annual RFPs to procure one-half of the required supply for commercial and industrial customers with demands of 500 kW or less (Group 2 customers) on one-year, full requirements contracts. The RFPs will procure full requirements contracts with 90% of the projected annual Group 2 load priced as a full requirements, load-following service, and the remaining 10% priced as a spot market purchase service.

The semi-annual RFPs will be held in October and March of the delivery year immediately preceding the prompt delivery year. Unlike UGI's earlier proposal, which called for a two-month procurement window, UGI will be limited to a one-month window to conduct the RFP, to address concerns from OSBA that the longer two-month window could lead to UGI attempting to "time the

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Briefly:

Viridian Energy Begins Offering PPL Residential Product

Viridian Energy has begun offering electric supply to residential customers in the PPL territory, according to the Office of Consumer Advocate's pricing comparison. As only reported in *Matters*, Viridian received its Pennsylvania supply license in February (Matters, 2/26/10). Viridian is offering a monthly variable product, with 20% renewable energy, priced at 9.299¢/kWh with no termination fee. The offer is currently the lowest priced publicly posted offer in the market, though it is just 0.001¢/kWh lower than Washington Gas Energy Services' offer of 9.3¢/kWh, which is fixed through January 2011.

Palmco Energy Receives Ohio Gas License

The Public Utilities Commission of Ohio granted Palmco Energy a natural gas supplier license to serve all customer classes in all service areas (Only in Matters, 2/8/10).

RD Energy Receives Ohio Gas Broker License

The Public Utilities Commission of Ohio granted RD Energy, Inc. a natural gas broker/aggregator license to serve all customer classes in all service areas (Only in Matters, 1/27/10). RD Energy recently received an Ohio electric broker license as well.

Calif. PUC Sets Hearing on CCA Ballot Measure

The California PUC has scheduled a public forum on March 17 to hear from those opposed to and supportive of Proposition 16, the ballot initiative supported by Pacific Gas & Electric which would require a vote of two-thirds of the residents within a community choice aggregation for the aggregation to be formed. Currently, CCAs may be formed through the actions of a local government without the need for a popular vote.

Energy Cooperative of New York Changes Name

New York and Pennsylvania competitive supplier Energy Cooperative of New York, Inc. has changed its name to the Energy Cooperative of America, Inc.

PUCT Staff Schedules Non-Wind RPS Workshop

PUCT Staff scheduled a workshop relating to Project 35792 (Rulemaking Relating to the Goal for Renewable Energy) for Wednesday, March 31, 2010. As only reported in *Matters*, Staff had previously issued a strawman proposal to create a 500 MW non-wind carve-out in the RPS (Only in Matters, 12/22/09).

Reach Energy Pays TDU Debts

Reach Energy informed the PUCT that it has paid all of its outstanding debts to Oncor, CenterPoint Energy, and AEP Texas Central (Only in Matters, 2/4/10).

CenterPoint Files for Waivers to Waive Meter Testing Fee, Distribute In-Home Devices

CenterPoint Energy filed in PUCT Docket 38039 for various waivers of the requirements of its delivery tariff and the Substantive Rules to allow it to provide one free meter test to customers with advanced meters, and to provide 500 in-home usage monitors to customers with advanced meters, in order to improve confidence in advanced meters. CenterPoint noted that Substantive Rules 25.341 and 25.343 generally prohibit a TDU from offering "competitive energy services," which could be interpreted as prohibiting the distribution of in-home usage monitors. Additionally, CenterPoint asked to waive the meter testing fee imposed on REPs (and typically passed through to customers) for customers seeking an initial test of their advanced meter. CenterPoint said that if the customer has already requested a test of their advanced meter, it reserves the right to impose a charge for any future tests within a four year period, as provided in the tariff, if the meter is, in fact, reading accurately (no charge is imposed for tests in which the meter is found to be inaccurate).

Champion Energy Wins Nabors Industries Contract

Champion Energy Services announced it has won a contract to provide electric energy for the ERCOT accounts of Nabors Industries, an S&P

500 oil, natural gas and geothermal drilling contractor. The 36-month contract goes into effect in May 2010.

RRI Energy to Withdraw Illinois Retail License

RRI Energy Solutions East petitioned the Illinois Commerce Commission to relinquish its alternative retail electric supplier license. As previously reported, RRI sold its Illinois book to MC Squared Energy Services, and no longer serves Illinois retail customers.

APX Expands to Voluntary Energy Efficiency Registration Services

APX, Inc. said that it has extended its registry services to include energy efficiency certificates in voluntary markets. APX has previously provided registries for state-mandated efficiency credit programs.

Pepco, Delmarva Seeking to Increase Working Capital Recovered in Md. SOS Rates

Pepco and Delmarva have petitioned the Maryland PSC to increase their recovery of cash working capital costs related to the provision of SOS, and have explicitly requested to recover the additional costs through the bypassable SOS rates, starting with the rates to be instituted on June 1, 2010.

Specifically, Pepco is seeking to add to the previously approved SOS rates the following amounts:

Pepco	
Residential	\$0.00094/kWh
Type I	\$0.00112/kWh
Type II	\$0.00102/kWh
Hourly	\$0.00072/kWh

Delmarva is seeking to add to the previously approved SOS rates the following amounts:

Delmarva	
Residential	\$0.000595/kWh
Type I	\$0.000862/kWh
Type II	\$0.000922/kWh
Hourly	\$0.000724/kWh

The required increase in cash working capital costs its due to both the move to weekly invoicing in PJM, as well as the general increase in SOS costs which has occurred since the cash working capital costs were set several years ago when generation rates were significantly lower.

Staff Says Allegheny Bill View Access Measure Should Not be Included in POR Discount

The costs of Allegheny Power's interim electronic bill view access mechanism should be recovered in base distribution rates, and not the purchase of receivables discount, Maryland PSC Staff said in comments in advance of today's administrative meeting (Only in Matters, 3/3/10).

As only reported by *Matters*, the short-term solution, which would create an online access portal to allow suppliers to view customers' bills, would cost \$50,000. The solution would only be in place until upgrades in Allegheny's customer information system to provide bill view access are completed (which will take at least 12 months). Providing competitive suppliers with electronic bill view access is a requirement of COMAR 20.53.

"Staff believes that it is inappropriate to recover programming changes for Bill-View through POR because this function is provided as consumer protection and as a benefit to customers. These benefits would accrue largely to smaller customers (or those less familiar with energy rate issues) that would need assistance handling bill disputes."

Staff said that if the costs of the interim solution were spread over base rates for residential and small commercial customers, the costs would be about 21¢.

In contrast, Staff said that placing the costs in the POR discount rate would essentially allocate such costs to medium and large commercial customers (since those are the classes currently shopping), even though such customers will benefit less from bill view access due to their greater sophistication in purchasing electricity.

ERCOT IMM Says March 8 Price Spikes Reflect Previously Noted Inefficiency in Zonal System

Market clearing prices for energy which hit the $2,250/MWh price cap in three of the ERCOT zones for the interval ending 2215 on March 8, 2010 can be attributed to large generation schedule reductions in the aggregate in the Houston, North, and South zones from the interval ending 2200 to 2215, and a violation of the West to North constraint to solve system power balance, ERCOT Independent Market Monitor Dan Jones said in an email to TAC and WMS members, in response to several questions about the prices.

For the interval ending 2215 on March 8, 2010, the MCPEs were as follows:

Houston:	$2,250.00/MWh
North:	$2,250.00/MWh
South:	$2,250.00/MWh
West:	($1.50)/MWh

For the interval ending 2200, scheduled generation was 35,446 MW and Scheduling, Pricing and Dispatch (SPD) load was 31,100 MW, with 613 MW of Up Balancing Energy Service (UBES) deployment and 4,959 MW of Down Balancing Energy Service (DBES) deployment. The West to North zonal constraint was binding and resolved.

For the interval ending 2215, scheduled generation was 30,470 MW and Scheduling, Pricing and Dispatch load was 30,400 MW, with 2,298 MW of Up Balancing Energy Service deployment and 2,368 MW of Down Balancing Energy Service deployment. The West to North zonal constraint was binding and unresolved.

Jones noted that the current zonal model imposes ramp constraints to limit changes in balancing energy deployments rather than limitations in total output. "Thus, even though load was decreasing from 2200 to 2215 (and, therefore, total physical generation output was decreasing) and the scheduled generation was very close to the SPD load in interval ending 2215, the current zonal model sees the need in interval ending 2215 to recall a majority of the 4,959 MW of DBES deployed in interval ending 2200, subject to ramp limitations (over 1,800 MW of DBES was still required in the West Zone to manage W-N congestion)."

"These ramp limitations not only prevented the recall of all of the non-West zone DBES deployed in the prior interval, but also prevented any UBES offered by QSEs with DBES recall limits from being deployed. Because of these limitations, the result was an artificial shortage of dispatchable energy in the Houston, North and South zones, thereby causing the W-N zonal constraint to be violated to access additional generation in the West zone to meet system power balance. Because of the high shift factors (approx. 0.82) associated with the W-N dynamic stability constraint in 2010, the violated W-N constraint shadow price of $5,000/MWh produced initial MCPEs in the South, North and Houston zones of approx. $4,000/MWh, each of which was then adjusted to the price cap of $2,250/MWh pursuant to the ERCOT Protocols, with a corresponding adjustment to the W-N shadow price. The highest offer dispatched in interval ending 2215 was $500.00/MWh," Jones said.

"These outcomes are a result of a market design inefficiency that is inherent in the zonal market model. Prior recommendations by Potomac Economics to address this issue in the zonal model were deferred by stakeholders to the nodal market implementation in which this issue will be addressed by individual unit dispatch instructions and unit-specific ramp constraints that limit changes in total production rather than just balancing energy deployments," Jones added.

N.H. PUC Approves PSNH Green Default Service Rate

The New Hampshire PUC approved Public Service of New Hampshire's application to offer certain default service customers a renewable energy option (09-186).

Unlike many utility-offered renewable options, the PSNH option will be a per kilowatt-hour adder to the otherwise applicable default service rate, rather than blocks of RECs.

PSNH will offer customers three renewable rate options: 1) a 25% option, 2) a 50% option, and 3) a 100% option. Under each option, PSNH will purchase and retire renewable energy certificates to match the selected percentage of the customer's actual energy use.

PSNH originally proposed a conservative (more expensive) adder for the optional renewable adder in order to reduce potential under-recoveries. PSNH originally estimated that the renewable adder would be between 3.8¢/kWh and 6.2¢/kWh for the 100% option, and later during hearings proposed an adder of 4.66¢/kWh for the 100% option.

However, the PUC said that, "it is appropriate for PSNH to more closely track the market price for RECs in establishing its rate for the renewable [default service] service option," noting the stable prices for RECs in the past two years. The PUC ordered PSNH to use its revised adders of 3.532¢/kWh for the 100% option, 1.766¢/kWh for the 50% option, and 0.883¢/kWh for the 25% renewable option.

The rates are based on the mid-point of actual market bid and offer prices for New Hampshire 2010 vintage Class I and II RECs as of January 22, 2010, which in turn were consistent with market prices in December 2009 and earlier months, the PUC said.

In setting the renewable rates going forward, PSNH will use a regulatory process similar to what it uses for rate setting and reconciliation of revenues and expenses associated with its default energy service. Under this approach, PSNH will forecast the expected customer participation and related costs for meeting the renewable service option on an annual basis for the next calendar year. Similar to the adjustment of its default energy service rate, PSNH will be permitted to make a mid-year adjustment to the renewable rate if the renewable energy market indicates a market price that is considerably higher or lower than the effective renewable service rate.

PSNH, in its original petition, said that it would move any over-collection to the default energy service docket, or make a contribution to the renewable energy fund with the surplus. PSNH said that it would not use the surplus to set an artificially low renewable service rate for the next rate period. However, PSNH also said that any over- or under-collection would be applied to the estimated renewable rate for the next rate period.

PSNH estimates that the incremental costs necessary to administer the renewable service rate will be about $114,000. PSNH proposed to recover these incremental costs from all customers through PSNH's distribution rates. Such costs include billing system upgrades, customer service training, PSNH website changes, marketing, promotion, and customer communications. In addition, PSNH said that it may also seek a grant from the renewable energy fund to offset specific marketing or promotion costs if presented with the opportunity to do so.

Under a settlement approved by the PUC, PSNH agreed that it will seek Commission approval before recovering these incremental marketing and promotion costs through PSNH's distribution rates. PSNH testified that these incremental costs would not exceed $125,000 annually.

PSNH said that it plans to market the renewable service option through a variety of means including: (1) press releases; (2) messages on the interactive voice response system at PSNH's customer call center; (3) a dedicated page on its website, (4) including information on the renewable service option in PSNH's EarthSmart branding program; (5) articles in PSNH's Living with Energy bill insert; (6) specific bill messages; (7) promotion via PSNH's media web sites such as its blog and Twitter; and (8) promotions at home shows, trade shows and chamber of commerce events.

PSNH testified that it decided to directly offer the renewable service option to its customers rather than providing retail access to competitive suppliers for a number of reasons. PSNH said it will be much simpler for PSNH to develop and implement the program itself within PSNH's internal infrastructure in place for the acquisition of RECs to comply with the electric renewable portfolio statute. PSNH also said that, when it began looking at providing retail access to competitive suppliers, it found that additional tasks would be required such as issuing an RFP, selecting a vendor, developing vendor contracts, monitoring those contracts, tracking revenues by vendor, and administering vendor payments.

The renewable option is only available to default service customers who are not enrolled in PSNH's residential electric assistance program rate (EAP), and who have not been approved to receive electric service payment assistance through the fuel assistance program administrated by the Community Action Agencies. The PUC confirmed, in its final order, that the program does not need to be offered to customers on competitive supply, as statute limits the requirement for a utility-offered renewable option to customers on default service.

Originally, PSNH proposed allowing customers to enroll in and drop from the renewable option on a billing cycle basis. For example, if a customer contacted PSNH on July 1 to enroll in the renewable program, and the customer's next meter read date was July 15, the customer's next bill for services would include a charge for the renewable service option. Similarly, if the same customer contacted PSNH on July 31 to drop from the program, the customer's next bill would not include the renewable service charge. PSNH said that it planned to provide customers with the ability to enroll in and drop from the program electronically through PSNH's website. According to PSNH, a customer using the website would be informed that it would take at least two business days to complete the transaction.

However, the PUC found in its order that enrollments and drops should occur at the next regularly scheduled meter read.

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purchase any receivables retroactive to the date on which the POR Billing System is implemented, and will not look favorably on any request from the Company for an extension of time to implement the POR Billing System."

In its letter to the PSC, Pepco does not specifically ask for a waiver of the April 1, 2010 deadline, only for an extension of time to file its compliance plan (though an associated delay in POR implementation is implicit, barring near immediate resolution of the Delmarva issues).

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market."

RFP bidders will be required to deliver power to the UGI distribution system, and will be responsible for procuring transmission, capacity and related services to facilitate such deliveries. Bidders will also be responsible for alternative energy portfolio standards (AEPS) compliance and associated costs.

UGI will continue to maintain an AEPS surcharge, however, to collect or refund, with interest, any AEPS over/undercollections carried over from periods prior to June 1, 2011. The AEPS surcharge will appear as a separate line item on Group 2 customer bills, but will be included in the Price to Compare.

Under the settlement, UGI reserves the right to propose in a future filing to enter into longer-term AEPS contracts for some of its Group 2 (and potentially other default service groups') default service AEPS requirements in order to, "facilitate the development of particular alternative energy projects that may need such longer-term arrangements to facilitate project viability." Parties reserve their rights to oppose such contracts in the future.

The default service rate for Group 2 Customers will be a single flat amount per kWh for all Group 2 Customers. In setting default service rates for the post May 31, 2011, period, UGI will be permitted to recover, or required to refund, any remaining over/undercollections incurred during the January 1, 2010, through May 31, 2011, period.

UGI shall be permitted to recover only the following administrative costs through its default service rates: (a) outside legal expense associated with default service filings and requirements; (b) costs associated with default service RFP processes, including independent third party monitoring costs for each supply group (i.e., residential and Group 2); and (c) load research-related costs.

Originally, UGI proposed to allocate administrative costs which could not be attributed to a particular customer class on the basis of the number of customers. However, under the settlement, such non-assignable administrative costs will now be allocated to default service rates through the amount of kilowatt-hour sales, rather than the number of customers.

The settlement provides that all load for commercial customers of 500 kW or less shall be grouped into one default service class due to the small amount of such load, rather than creating a separate small commercial class (such as under 25 kW or 100 kW) and a medium commercial class. "It would be difficult for UGI to acquire supplies for these smaller subgroups while still procuring supplies on at least two different dates to help avoid the effects of potential transient events on wholesale energy prices," the settlement holds. According to a UGI discovery response, the combined peak load of the proposed Group 2 class is only 78 MW, which is equivalent to two 39 MW tranches.

In the event of wholesale generation supplier non-performance, UGI will purchase replacement supplies in the PJM-administered spot market in a commercially reasonable manner. In addition, UGI will, within a commercially reasonable time period, initiate a competitive solicitation process to acquire replacement supplies consistent with its procurement plan.

UGI will continue its practice of meeting with any interested Electric Generation Supplier to discuss the coordination of the provision of customer information or other issues related to UGI-supplier retail choice coordination, and to continue to follow Electronic Data Exchange Working Group standards.