Energy Choice Matters

November 25, 2009

# PECO Applies to Implement Electric, Gas POR Programs With Little to No Discount

PECO applied to institute a Purchase of Receivables program for low volume transportation gas customers, and a revised program for all classes of electric customers, with both programs featuring no recourse and either a zero or minimal discount rate.

PECO said that the non-recourse nature of the programs and the minimal to zero discount rate, "will give retail suppliers more certainty regarding payment and thereby enhance retail competition."

PECO's electric POR filing was made in compliance with the provisions of its default service settlement for the period starting January 1, 2011 (Matters, 4/17/09). The gas POR program is voluntary and reflects the Pennsylvania PUC's desire that LDCs implement POR programs.

The electric POR program would be effective January 1, 2011. The gas POR program would be effective January 1, 2012.

The two programs would share many elements. POR would be non-recourse, and there would be no reversion to dual billing after 90 days of uncollectibles as is the case in PECO's existing electric POR program.

Receivables in the gas POR program would initially be purchased with no discount, with $1.5 million in incremental IT costs deferred. PECO said that due to the low volume of shopping in its gas choice program, charging suppliers implementation costs through a discount upon program initial may hinder the development of a competitive retail market as the discount rate would likely be

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# Proposed Order Would Allow 20-Year Renewable PPAs for Illinois Default Service

The Illinois Power Agency (IPA) would be allowed to procure long-term, bundled renewable contracts to serve default service load under a proposed order from an Illinois Commerce Commission ALJ (09-0373).

In a draft order approving the IPA's procurement plan, the ALJ recommended allowing the IPA to procure 20-year PPAs bundling energy and RECs under the terms proposed by the IPA (Only in Matters, 11/10/09).

The volume to be purchased on long-term PPAs would be 3.5% of the portfolio, or 2 million MWh annually over the 20-year period for a total purchase of 40 million MWh. The 2 million MWh annually would be split as 1.4 million MWh at Commonwealth Edison and 600,000 MWh at the Ameren utilities.

The proposed order calls the 20-year PPAs "reasonable," stating that the bundled energy and RECs, "will potentially benefit utility customers."

Prices for the long-term PPAs would be set through the IPA's competitive RFP process, where the contract terms will be standardized and winning bids will be selected on the basis of price alone. The RFP criteria will require all offers to be in the form of a base price with a fixed escalation rate of 2% per year, provided that allowances for short-falls and carry-overs in production will be priced as of the year delivery was/is due.

As more fully discussed in our 11/10/09 story, the procurement would be open to both existing

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## ConEd Would Implement Rate Ready Collaborative under Electric Joint Proposal

Consolidated Edison would establish a collaborative proceeding to consider modifications to its rate ready utility consolidated billing model to permit electric ESCOs to offer and bill for products which reflect time-of-use, interval, and real-time pricing, as well as to offer multiple rate components, such as demand, on-peak, and off-peak usage, under a joint proposal filed in its current electric rate case (09-E-0428).

The collaborative would begin in December 2009 with parties intending to complete the collaborative process within eight months, with submission of a joint proposal to the Commission if stakeholder agreement can be forged.

Per the joint proposal, the collaborative is to examine all issues relative to implementing the aforementioned modifications, including, but not limited to, the amount of system upgrade and related costs; the appropriate manner by which related system upgrade costs will be determined and recovered; and identification and development of an appropriate implementation schedule if it is determined that such modifications are reasonable and necessary. Neither Con Edison's nor other parties' agreement to participate in the collaborative shall be construed as agreement or acknowledgement by Con Edison or such parties that Con Edison's investors or its customers should bear any of the costs of any modifications made as a result of the collaborative.

The parties acknowledge that the costs for undertaking any modifications to Con Edison's rate ready utility consolidated billing model are not considered in developing the joint proposal, and Con Edison will not be required or expected to defer any other work in order to implement such modifications. Con Edison will incur incremental costs (e.g., for consultants) in order to implement modifications to the rate ready billing model. The joint proposal holds that any capital expenditures required to implement any modifications should not be counted against any capital spending target or net plant target, and that the incremental capital and O&M costs incurred by Con Edison to implement such modifications will be fully recoverable by the company in a manner determined by the Commission.

Regarding the potential unbundling of transmission rates from delivery rates raised in ConEdison's initial filing (Only in Matters, 10/23/09), the joint proposal holds that if the PSC does not initiate a generic proceeding to consider unbundling transmission and distribution rates before the end of Rate Year 1, nothing in the joint proposal shall be construed as (a) limiting ConEdison's rights to pursue unbundling of its transmission and distribution rates to be effective no earlier than April 1, 2013, and (b) indicating that the signatory parties' agreement or acknowledgement that ConEdison's transmission and distribution rates should be unbundled. Prior to filing any petition for unbundling, ConEdison will convene a meeting of interested parties to discuss its planned filing.

The joint proposal provides that if the New York ISO implements weekly billing during the term of the electric rate plan, and ConEdison experiences an increase in working capital requirements from weekly billing, ConEdison may recover the increase in working capital requirements through a tariff filing that would implement a change to the Merchant Function Charge to recover any incremental costs.

The joint proposal was signed by ConEdison, PSC Staff, the Retail Energy Supply Association, Small Customer Marketer Coalition, Consumer Power Advocates, the New York Energy Consumers Council and several additional parties.

## ALJs Favor Release of NYSEG, RG&E Data Used in Gas Cost Forecasts

Two New York ALJs denied NYSEG and Rochester Gas & Electric's request for confidential treatment of certain data relating to gas commodity costs, pipeline transportation and storage charges, and financial hedging costs submitted in pending rate cases (09-G-0718 et. al.), finding that the NYSEG and RG&E's request for confidentiality did not meet the limited exception to the state's Freedom of Information Law (FOIL).

However, because the harm postulated by NYSEG and RG&E resulting from disclosure of the information to marketers could not be undone by a decision overturning the ALJs' ruling, the ALJs granted the LDCs' request for restricted status, since the ALJs' ruling may be appealed. Until the information has lost its protected status under the Commission's rules, it may not be disclosed to natural gas marketers even if they have agreed to be bound by the Protective Order in the case.

The information at issue includes model inputs for gas commodity costs, pipeline transportation and storage charges, financial hedging costs, and system throughput, and the calculations by which the inputs are combined to produce the weighted average monthly and annual gas cost forecasts.

NYSEG and RG&E requested confidential status because they argued that public disclosure of the information would provide competitors with an unfair economic or competitive advantage, and could harm the LDCs' customers.

With the information, marketers and suppliers could ascertain the LDCs' cost of doing business and their patterns and parameters in negotiating prices for gas, which, in turn, could be used to gain unfair bargaining advantage over the LDCs, NYSEG and RG&E noted. Competitors, the LDCs warned, could use the information to estimate the LDCs' commodity cost of gas, and then with that knowledge, attempt to alter their own hedging strategies and price offerings to the financial detriment of the LDCs' customers.

Specifically, the information could allow marketers, "to determine the optimal times to add or drop customers as well as the amounts to charge customers," and to determine when there are potential opportunities for increased marketing activities to attract customers or encourage customers to migrate back to the LDCs, NYSEG and RG&E said.

Additionally, NYSEG and RG&E claimed that it would be unfair to disclose the information to marketers participating in the rate case, because such marketers could unfairly gain a competitive advantage over marketers who do not participate, disrupting the gas supply market to the detriment of New York customers.

Although no party has yet objected to the request for confidential status, the ALJs denied the request, finding that NYSEG and RG&E themselves would not be harmed by the disclosure, which is the only applicable standard under the law.

NYSEG and RG&E concede that as they are entitled to cost recovery, disclosure would not harm them, but rather their customers. The ALJs noted that the Freedom of Information Law only grants confidential status if the records would, if disclosed, cause substantial injury to the competitive position of the commercial enterprise that made them available. "The exception does not apply. The information must be disclosed," the ALJs found.

Even if the law allowed the ALJs to provide confidentiality based on the general impact on competition, as opposed to the companies themselves, the ALJs would still require disclosure of the information.

The ALJs first concluded that, "the assertion that knowledge of the utilities' commodity costs and hedging practices could enable marketers to change their own hedging and pricing practices to the detriment of consumers is completely unsupported by any information establishing a link between the knowledge and the harm."

"Certainly, it is hard to imagine that marketers stand to gain anything by deliberately setting their prices above those of the Companies, and if they deliberately set them lower, it is difficult to see how that is harmful to their customers," the ALJs noted.

"It is equally unclear how it would be harmful to customers or competition for marketers to have a better sense of when to actively pursue new business and when not. One would expect sales to pick up when marketers are able to offer good prices to customers, and to tail off when they cannot. That is fairly fundamental to all price-based competition," the ALJs added.

"Finally, the argument that marketers participating in this proceeding and receiving responses to information requests will 'unfairly gain a competitive advantage' over those who do not, is simply wrong. If marketers who expend time and resources participating in these cases are able to learn of public information that non-participating marketers may not know about, any competitive advantage they gain from their efforts is fairly earned. This is no different than the advantage gained by a marketer who reads and studies utilities' tariffs over those who do not. Our obligation is to assure that our proceedings are open to all interested parties," the ALJs held.

# *Briefly:*

**Cape Light Compact Announces New Rates**
The Cape Light Compact announced basic service supply rates for the January 2010 through July 2010 meter-read dates:

| | |
|---|---|
| Residential | 8.790¢/kWh |
| Small Commercial | 9.260¢/kWh |
| Large Industrial | 9.019¢/kWh |

The Cape Light Compact aggregation will again be supplied by ConEdison Solutions. Joseph Soares, Cape Light Compact's Senior Power Supply Planner, encouraged customers who have left the aggregation to, "take a second look," at the Compact's rates.

**Summit Energy Services Seeks Pa. Broker License**
Summit Energy Services applied for a Pennsylvania electric supply license as a broker/marketer, seeking authority to serve all sizes of commercial and industrial customers in all service areas.

**Goldstar Energy Seeks Pa. Broker License**
Goldstar Energy Group, Inc. applied for a Pennsylvania electric supply license as a broker, seeking authority to serve all customer classes in all service areas.

**Harrisburg PBS Station to Run Program on Rate Cap Expiration**
Harrisburg PBS station WITF-TV will air a public forum to give viewers advice and information on the expiration of PPL rate caps today (Nov. 25) at 8 p.m. The "Caps Off" forum will be made available online at www.WITF.org. Panelists include Pennsylvania PUC Chairman James Cawley; Pennsylvania Consumer Advocate Sonny Popowsky; PPL Electric Utilities President David DeCampli; and Andrew Kleit, Professor of Energy and Environmental Economics at Penn State. GDF SUEZ Energy Resources NA is sponsoring the forum.

**TNMP, Fort Stockton Settle Billing Error Dispute**
Texas-New Mexico Power and the City of Fort Stockton have executed a settlement agreement and mutual release regarding billing errors dating back to before deregulation, and TNMP withdrew its request for declaratory order from the PUCT regarding the billing errors (37585, Only in Matters, 10/21/09). Terms of the settlement were not disclosed.

**ERCOT Posts 4CP Data**
ERCOT has posted the 2009 Four Coincident Peak Load Calculation for each Transmission/ Distribution Service Provider on its website (.xls file), and in PUCT docket 37680. The Four Coincident Peak dates for 2009 were June 25, July 13, August 5, and September 3, 2009.

**PECO Sets Gas Supply Rate**
PECO's gas supply rate effective December 1, 2009, will be $1.20 per Ccf of natural gas, compared with the current $1.14 per Ccf, and $1.45 per Ccf last January, for an average residential heating customer using 160 Ccf of natural gas per winter month.

**Ambit to Move Illinois Customers to New Entity**
Ambit Illinois LLC applied for an Illinois alternative gas supplier license so that all customers currently served by the existing Ambit Energy LP entity may be migrated to Ambit Illinois LLC. Ambit Energy LP will cease operations after transferring customers to the new entity. As done currently at its sister company, Ambit Illinois would market to residential and small commercial customers at Peoples Gas, North Shore Gas and Nicor Gas. Ambit Illinois will still market as Ambit Energy.

**LPB Energy Management Opens D.C. Office**
LPB Energy Management has opened a Washington, D.C. office to expand business development opportunities with the federal government.

## *PECO POR ... from 1*

relatively high to recover all costs from a small base of migrated customers.

Receivables in the electric POR program would initially be collected at a 0.2% discount, to recover $2 million in incremental IT costs. PECO expects such costs to be paid off by December 2011. Once the costs are paid off, the discount rate would be set at zero. The 0.2% discount rate is uniform as PECO does not believe that the incremental costs differ based on customer class.

No uncollectible costs would be collected through the discount rate, and any uncollectible expense would initially be recovered though base rates, which PECO said would provide a level playing field for suppliers. PECO reserved the right to institute a nonbypassable, non-reconcilable uncollectible surcharge to recover such costs in the future as opposed to using base rates.

Both the electric and gas POR programs would only purchase receivables billed on utility consolidated billing. Additionally, all amounts billed on utility consolidated billing would be required to participate in the POR program.

However, there would be no all-in/all-out requirement for POR participation, even within specific customer classes. Suppliers could use dual or supplier-consolidated billing for any accounts they wish, while still being able to place other accounts on POR. Since PECO is not recovering uncollectibles through a discount rate, there would be no provision to adjust a supplier's discount rate to reflect its actual uncollectibles versus the discount rate, as is the case at other Pennsylvania utilities (such as Duquesne Light and PPL).

Gas receivables would be paid to suppliers within 40 calendar days. Residential electric receivables would be paid within 25 calendar days, and non-residential electric receivables would be paid within 20 calendar days.

POR would only cover basic supply service for both electric and gas service. For electricity, PECO would define basic supply service consistent with the PUC's finding in the PPL POR order that basic supply service includes renewable energy or REC costs bundled with delivered energy. Basic supply costs exclude REC products not tied to delivered energy, and other energy management, service or warranty products.

PECO would have the right to terminate customers for non-payment of supplier charges, regardless of whether such charges exceed what customer costs would have been under default service. PECO will purchase receivables as of the programs' respective effective dates, and thus a customer may be terminated for outstanding receivables incurred prior to the effective date of the programs.

The gas POR program was filed in docket P-2009-2143588. The electric program was filed in docket P-2009-2143607.

## *Illinois ... from 1*

and new generation. The REC portion of the procurement will count towards the RPS requirements and comply with the bill-impact cap set forth in statute. The procurement will also, to the extent available, procure at least 75% of the renewable energy from wind, with statutory cost effective tests and locational preferences also applied.

The proposed decision rejects several protests from the Illinois Competitive Energy Association regarding the long-term PPAs (Only in Matters, 11/16/09), noting that concerns raised about various other statutory mandates for long-term contracting (such as for integrated gasification combined-cycle coal plants) are not within the Commission's purview.

The IPA will also procure short-terms RECs to meet the RPS requirements. The power agency had proposed conducting a single solicitation for RECs at both Ameren and ComEd, as opposed to the utility-specific procurements used in the past.

The draft order rejects the IPA's single short-term REC procurement in favor of separate procurements for each utility, citing Staff's concern that conducting each utility's solicitation simultaneously could force bidders to choose to only offer RECs in response to one utility's requirements, decreasing competition. In contrast, if separate, non-simultaneous procurements are held, bidders can offer all of their RECs into the first procurement, and if unsuccessful in selling all of their RECs, can offer their entire remaining REC supply in the subsequent auction, maximizing competition, Staff said.

Also regarding RECs, the proposed decision would deny Constellation Energy's request to allow the use of Green-e RECs, and APX's proposal to use the North American Renewable Registry.

**Demand Response**

The proposed order would allow the IPA to procure supplemental demand response capacity as part of its spring procurement, but would reject the use of a second procurement exclusively for demand response.

While the IPA had argued for procuring demand-side capacity in both the spring all-source procurement and a separate, carve-out procurement, ComEd noted that PJM already procures demand response in the Reliability Pricing Model, contending that RPM satisfies statutory requirements for the procurement of least-cost demand resources, and that additional procurements would add to ratepayers' costs.

The proposed order, however, says that, "[a]lthough it is not obvious to the Commission that the IPA's proposed supplemental demand response process can meet all such [statutory] requirements, the Commission believes it should be provided an opportunity to attempt to do so." Thus, the proposed order would authorize the IPA to undertake a supplemental demand response acquisition for ComEd in the spring of 2010, provided it meets all applicable statutory provisions.

"Specifically, the IPA shall document that any supplemental demand response measures that it acquires for ComEd meet the total resource cost test defined in Section 1-10 of the IPA Act. Additionally, the IPA shall document that any supplemental demand response measures acquired have a cost that is lower than procuring comparable capacity products, and that they produce electric service at the lowest total cost over time, taking into account any benefits of price stability."

The Commission will limit the supplemental demand response procured by the IPA to demand response from "eligible retail customers," defined as those customers who are served on fixed-price default service and who have not been declared competitive.

Procurement of supplemental demand response measures from sources other than eligible retail customers does not appear to be consistent with the statutory requirements and would not be adopted, the proposed order says.

The spring all-source procurement would also procure demand response capacity at Ameren, but since Ameren is not in PJM, such procurement would not be supplemental demand response and would not be subject to the additional scrutiny.

The proposed order would deny the IPA's fall, carve-out demand response procurement, because, "in terms of cost, it is not clear how such a solicitation for demand response measures could be directly compared to comparable capacity products as required by Section 16-111.5 of the [Public Utilities Act]."

**Other Issues**

The draft order would accept the IPA's plan to continue to procure 110% of supplies in the months of July and August, with no such oversubscription in other months, as the Commission says it would defer to the IPA's judgment on this issue.

The proposed decision would also set the following maximum Alternative Compliance Payment (ACP) rates for RPS:

**2009-2010 Plan Year**

| | Max ACP Rate ($/MWh) | Projected Deliveries (MWh) |
|---|---|---|
| Ameren | $ 0.938 | 17,700,274 |
| ComEd | $ 1.007 | 39,469,952 |

**2010-2011 Plan Year**

| | Max ACP Rate ($/MWh) | Projected Deliveries (MWh) |
|---|---|---|
| Ameren | $ 1.476 | 16,525,235 |
| ComEd | $ 1.598 | 35,993,039 |

Actual Alternative Compliance Payment rates applicable to competitive suppliers are not determined until the IPA has contracted for RPS requirements.

The draft order would accept the IPA's

proposed three-year laddering process, but would require the IPA to analyze the trades-off between price stability and risk premiums under laddering, as suggested by Staff.

The laddering procures 35% of requirements two years ahead of delivery, 35% one year ahead of delivery, and 30% in the year of delivery. As proposed, procurements will be for monthly on-peak and off-peak standard wholesale block energy products (or their equivalent volumes in seasonal or varietal strips).