Energy Choice Matters

March 19, 2009

PUCO Orders Mitigation of AEP Rates in ESP, Makes POLR Charge Bypassable

PUCO approved a modified version of the AEP Ohio utilities' electric security plan, mitigating generation rate increases with recovery via nonbypassable surcharge through 2018, while affirming that a proposed POLR charge must be bypassable. By law, AEP has the right to withdraw the ESP due to such modifications; it is currently reviewing PUCO's order.

While AEP had proposed a 15% limit on rate increases resulting from higher fuel costs under the Fuel Adjustment Clause (FAC), PUCO found economic conditions warrant even greater mitigation, and ordered that rate increases are not to exceed, on a total bill basis, 7% for Columbus Southern Power and 8% for Ohio Power in 2009. Increases will be limited to 6% for CSP and 7% for OP in 2010, and 6% for CSP and 8% for OP in 2011.

"[A] phase-in of the increases is necessary to ensure rate or price stability and to mitigate the impact on customers during this difficult economic period," PUCO said.

The mitigation results in approximate overall average generation rates of 5.47¢/kWh for CSP and 4.29¢/kWh for OP in 2009. Rates in 2010 will be 6.07¢/kWh at CSP and 4.75¢/kWh for OP, while 2011 rates will be 6.31¢/kWh for CSP and 5.31¢/kWh for OP. Rates will be retroactive to January 1, 2009, which the Ohio Consumers' Counsel believes is unlawful.

Costs in excess of the mitigated rates will be deferred, with carrying costs of 14%. Unless FAC costs are below the mitigated rates during the ESP which runs through 2011 (at which time deferral recovery would begin immediately), deferrals will be recovered through a nonbypassable surcharge starting in 2012 and lasting through 2018.

Continued Page 4

Mich. PSC Requires Net Metering Payments at Monthly Average LMP, or Contract Rate

Competitive suppliers, now required to offer net metering under Michigan law, will be required to compensate customers with generation in excess of 20 kW at either a monthly average LMP, or the supply rate in their customer contracts, under an order issued by the Michigan PSC (U-15787, U-15803, U-15919). Suppliers have said the compensation mechanism will discourage fixed-price contracting (Matters, 3/10/09).

Customers with distributed generation systems in excess of 20 kW are to be paid for excess generation at either: (1) the monthly average real-time locational marginal price for energy at the commercial pricing node within the electric provider’s distribution service territory, or, for net metered customers on a time-based rate schedule, the same measure during the time-of-use pricing period; or (2) the supplier's power supply component of the full retail rate during the billing period or time-of-use pricing period.

Competitive suppliers have noted that the use of monthly average LMPs or the contract supply rate will not reflect the value of excess generation at the time of production, possibly forcing the supplier to pay customers more for generation than it is worth in the real-time market.

Continued Page 5

PUCO Further Clarifies RTO Market Monitoring Requirement for MRO

PUCO further clarified the market monitoring criteria a utility must meet in order to offer a Market Rate Offer under SB 221. Under PUCO's rules, a utility may only offer an MRO if it is a member of an RTO, and the RTO has certain market monitoring safeguards.

In PUCO's original September 2008 rules, the Commission required a utility wishing to offer an MRO to be a member of an RTO that retained an independent market monitor that had the ability to effectively mitigate the conduct of market participants.

However, such a requirement was clouded when FERC moved certain types of market monitors out of the mitigation and tariff administration function, leaving such duties to the RTOs. FirstEnergy's MRO application was denied for, among other reasons, uncertainty regarding whether the Midwest ISO met the rule's market monitoring standard.

A February order changed PUCO's original finding and held that as part of an MRO application, the RTO must maintain an independent market monitor "function" (as opposed to an independent market monitor) that can screen and mitigate market power, ostensibly allowing RTOs in which mitigation is performed by the RTO to qualify under the MRO criteria.

PUCO yesterday further clarified that it is the RTO that must have the ability to identify any potential for market participants and electric utilities to exercise market power.

Additionally, PUCO removed an explicit reference in the rule that the market monitor must be able to identify potential market power in bilateral markets. As phrased now, the RTO must have the ability to identify potential market power in "energy, capacity, and/or ancillary service markets."

Suppliers Oppose MISO Short-Pay Mechanism in Capacity Auction

A proposal from the Midwest ISO to short-pay capacity suppliers under any bidder defaults in its Module E Voluntary Capacity Auction would unfairly force suppliers to bear the burden of such defaults, suppliers and marketers said in protests at FERC (ER09-757).

Under MISO's proposal, if a Market Participant fails to pay its bid for capacity in the voluntary auction, MISO would short pay capacity suppliers to the extent that the bidder's credit does not cover the invoice. Rather than receiving the auction clearing price, capacity suppliers would be paid their offer price, with additional funds, if any, paid on a pro rata basis to suppliers. Any incremental capacity not paid for would be "released" (not purchased).

Furthermore, MISO will use the proceeds of the capacity auction to first pay off unrelated debts owed to MISO from any defaulting capacity bidder. Essentially, that provision makes the winning suppliers the effective credit backers for all of the defaulting market participant's debts to MISO, Integrys Energy Services noted.

The process differs from how defaults are handled in other MISO markets, where winning suppliers are paid the auction clearing price even in cases of default.

The risk to the supplier of being paid as offered, rather than receiving the clearing price, and the risk of having its capacity released after the auction closes, will be considered by suppliers in determining their auction offers, Reliant Energy noted. Integrys Energy Services agreed that the risks may result in a premium on prices.

Integrys Energy Services offered an alternative approach to defaults under which failure to pay an invoice would result in the capacity involved never actually being purchased. Under this scenario, the market would be re-cleared in the case of a default, resulting in a new clearing price to be paid to all winning suppliers, with the auction outcome the same as if the defaulting buyer had never submitted a bid. There would also be no uplift under Integrys' plan.

NMISA Says Northern Maine Market is Interstate Commerce

The Northern Maine market "without question" includes interstate commerce, the Northern Maine Independent System Administrator said at FERC in replying to an argument raised by New Brunswick Power Generation (EL09-32).

In answering a complaint from Integrys Energy Services over its market-based rate authority, New Brunswick Power Generation has claimed that the NMISA market is not subject to FERC jurisdiction, since the isolated market does not involve interstate commence (Matters, 2/24/09).

The NMISA took no position on the merits of the complaint in the proceeding.

However, it did stress that sales for resale that take place in the NMISA region are indeed subject to the Commission's jurisdiction because the region includes interstate commerce.

Northern Maine is in interstate commerce by virtue of its connection with the rest of the United States through the transmission facilities of New Brunswick Power Transmission, whose transmission lines are used daily to facilitate transactions between the regions, NMISA said. Commission precedent and other language in the Federal Power Act make clear that the definition of interstate commerce includes the transmission of energy from one state to another even if the energy passes through another country en route, NMISA contended.

NMISA noted that FERC has held that Maine Public Service, whose transmission facilities are located exclusively in Northern Maine, is, "a public utility which sells electric energy to wholesale customers for resale in interstate commerce." MPS, NMISA added, is a Commission-jurisdictional transmission provider with an Open Access Transmission Tariff on file with the Commission.

WGL Questions Liquidity of Capacity Release Market

The level of competitive capacity releases is so low that, "legitimate questions can be raised regarding the adequacy of the liquidity of the competitive capacity release market," Washington Gas Light told the District of Columbia PSC in answering questions raised by the Office of People's Counsel regarding the utility's asset optimization programs (FC 874).

WGL has not seen any improvement in the unbundled capacity release market which can be attributed to FERC Order 712, though it welcomed the lifting of the release rate cap by FERC.

For that reason, WGL said its self-managed optimization program, which uses bundled transactions in the wholesale market, is preferable to straight capacity releases via auction. While the lifting of the capacity release rate cap may produce some additional revenue, it is not clear such revenue will be meaningful, as auctions continue to yield inferior revenues to bundled transactions, WGL said.

Easton Utilities Seeks Exemption from RM 35

Easton Utilities Commission asked the Maryland PSC to exempt it from ongoing proceedings in RM 35 addressing the competitive gas market, and to exempt it from any rules arising from the proceeding (Matters, 3/11/09).

RM 35 would establish various enrollment and billing regulations applicable to competitive gas supply in Maryland. At a recent rulemaking session, the Commission sent the proposed rules back to stakeholders to clarify how the rules will apply to transportation level customers versus retail customers of LDCs that have choice.

As a municipality, Easton does not offer retail gas choice, and asked that the scope of the proposed rules not be expanded to cover larger customers in areas where competitive retail supply is not available.

Briefly:

Mich. PSC Leaves Return to Service Rules to Rate Cases

Revising return to utility service provisions and rates should be raised in individual rate cases, the Michigan PSC said in an order declining to implement a uniform standard in case U-15897 (Matters, 10/22/09). Furthermore, any changes to return to bundled service procedures will be deferred until the Commission adopts rules for administration of the 10% electric choice cap.

Gasearch Receives Ohio Retail License

PUCO approved Gasearch as a retail natural gas marketer and aggregator (Matters, 2/16/09). Gasearch, which currently serves General Transport C&I customers at Dominion East Ohio, intends to expand to non-transportation C&Is in the service area.

ERCOT Board Increases Requested Nodal Fee

The ERCOT Board has revised its recommendation for the nodal market funding mechanism to maintain a minimum 40% equity, authorizing ERCOT Staff to make a filing with the PUCT requesting a nodal surcharge between 32-38¢/MWh for 2010. The amount depends on the Commission's pending decision regarding the fee for the remainder of 2009. In February, the Board had voted to seek a surcharge of 27-28¢ (Matters, 2/18/09), but the Commission's concerns regarding the declining level of revenue funding for the nodal project prompted the revision.

TXU Offering Grants for Low-Income Energy Efficiency

TXU Energy launched a low income energy efficiency assistance program which will provide grants to local social service agencies across Texas for turnkey energy efficiency services as well as funds for agencies to purchase energy efficient products to help reduce energy usage in low-income single-family homes and apartment complexes.

AEP *... from 1:*

While some parties had argued deferral recovery should be limited to the period of the ESP, to reduce carrying costs and also prevent prolonged nonbypassable surcharges which inhibit competition, PUCO said limiting the amount of time over which the deferrals could be collected would not ensure rate stability and could produce excessive rates.

The base FAC costs were set using Staff's proxy which updated known 2007 fuel costs in order to estimate 2008 levels.

PUCO denied AEP's request to automatically increase base generation rates during the term of the ESP. AEP had proposed increasing the non-FAC portion of the generation rate by 3% for CSP and 7% for OP for each year of the ESP, to recover environmental investment carrying costs and other items. PUCO agreed with Staff that such environmental carrying costs should be recovered through a separate future proceeding after such investments have been made.

The AEP utilities had proposed increasing the nonbypassable POLR charge from 0.8 mills to 6.08 mills for residential customers; from 0.7 mills to 5.2 mils for Small General Service (GS-1) customers; from 0.6 mills to 5.3 mills for Medium General Service (GS-2) customers; and from 0.5 mills to 3.5 mills for Large General Service (GS-4) customers (Matters, 11/4/08).

While PUCO agreed AEP has some risk due to its POLR status, it agreed with marketers and Staff that the proposed POLR charges are too high, and that risk can be mitigated by properly pricing return to standard service provisions.

Accordingly, PUCO ruled that the POLR charges are to be bypassable for shoppers who agree to return to default service at a market price. PUCO set the POLR charge at 90% of the estimated POLR costs, directing AEP to develop a POLR rider to collect a revenue requirement of $97.4 million for CSP and $54.8 million for OP (versus proposed requirements of $108.2 million and $60.9 million, respectively).

The Commission also rejected, as part of the FAC, AEP's proposal to purchase incremental power on a slice of system basis equal to 5% of each company's load in 2009, 10% in 2010, and 15% in 2011. PUCO denied the request since AEP said purchased power is not a prerequisite for adequately serving the additional load requirements assumed by AEP when adding Ormet Primary Aluminum and former Monongahela Power customers to its system. "We struggle ... to find a rational basis to approve such a proposal in the absence of need," PUCO said.

AEP's plan to recover costs of compliance with alternative energy standards through the FAC was approved, with PUCO stressing such alternative energy portfolio costs are to be fully bypassable, and cannot be included in any FAC deferrals which will be nonbypassable.

PUCO deferred acting on the question of whether customers taking the AEP Standard Service Offer should be allowed to participate in PJM demand response programs. The Commission asserted it has authority to rule on customers' eligibility, but said it is not convinced, as AEP argues, that a bundled customer's participation in demand response programs amounts to the resale of energy provided by AEP. Such resale is prohibited by tariff.

Still, PUCO is concerned that bundled customers' participation in PJM demand response programs costs AEP's other customers, since the participating customers' load is included in AEP's Fixed Resource Requirement, and the cost of meeting that requirement is reflected in AEP's retail rates.

Since the Commission said it does not have sufficient information regarding both the potential benefits to program participants and the costs to Ohio ratepayers, it concluded the issue must be decided in a separate proceeding. While not ruling on the merits of default service customer participation in PJM load response, PUCO did require AEP to modify its ESP to eliminate the provision that prohibits participation in PJM demand response programs at this time.

In a concurring statement, PUCO Chair Alan Schriber and Commissioner Paul Centolella said it is "essential" that consumers benefit from demand response in terms of a reduction in the capacity for which AEP customers are responsible. The duo also said that, in addition to the Standard Service Offer rate, consumers should have the opportunity to see and respond to changes in the cost of power, encouraging AEP and stakeholders to develop dynamic pricing options for C&I customers.

Initially under the ESP, AEP will no longer offer a green energy or REC option, as PUCO refused to direct AEP to reinstate the tariffs after they lapsed at the end of 2008 as requested by consumer advocates. AEP said it intends to develop new green offerings in the future.

PUCO rejected AEP's application to create a regulatory asset rider to recover a variety of regulatory assets that were authorized in various Commission proceedings regarding AEP's electric transition plan, rate stabilization plan, line extension program, green pricing power program, and the transfer of the MonPower service territory to CSP. The Commission agreed with Staff that such costs should be evaluated in a distribution rate case.

Net Metering ***... from 1:***

Competitive suppliers had suggested that generation credits should be paid based on real-time LMPs.

To avoid the risk of losses from net metering compensation, Energy Michigan had cautioned that competitive suppliers will be incented to offer only products indexed to real-time prices, because then the contract supply rate will equal the rate available to suppliers when selling the excess generation in the spot market, preventing any under-recovery. Conversely, fixed-price contracts will be discouraged, because suppliers will face uncertainty regarding recovering costs of buying excess generation from customers, in cases where the real-time LMP is lower than the contract supply rate.

Customers with generation of 20 kW or less will be paid the full retail rate for the net of the bidirectional flow of kWh across the interconnection with the utility, consistent with legislation. The full retail rate includes the power supply and distribution components of the cost of service. The rate does not include any system access charge, service charge, or other charge assessed on a per meter basis.

Competitive suppliers noted that they cannot be required to reimburse customers for distribution under state law. Accordingly, the Commission held that for smaller net metered customers served by a competitive supplier, the distribution component of the full retail rate shall be paid by the utility, while the supplier must compensate the customer for the commodity portion.

Credit for excess generation shall appear on the next bill, and shall be carried forward for use in subsequent billing periods. At the end of each calendar year, the suppliers shall carry forward the remaining credit amount. Under the rules, RECs are owned by the customer generators.

Competitive suppliers are required to submit a net metering program plan consistent with the Commission's order within 30 days of the effective date of the rules, or by May 4, 2009, whichever comes first.

Retail suppliers are required to provide net metering customers with electric service at nondiscriminatory rates that are identical, with respect to rate structure, retail rate components and any monthly charges, to the rates that the net metering customer would be charged if the net metering customer were not participating in the net metering program. Suppliers may charge customers a maximum of $25 for a net metering application fee.