Energy Choice Matters

October 5, 2009

NOPEC, Gexa Seek Waiver, if Required, to Allow for Five-Month Pricing in 2011

The Northeast Ohio Public Energy Council and Gexa Energy petitioned the Public Utilities Commission of Ohio for a waiver, if deemed necessary, of the Ohio Administrative Code to allow NOPEC to offer customers a five-month fixed price from January 1, 2011 (when current pricing with Gexa ends), through May 31, 2011 (the end date of the FirstEnergy utilities' standard service offer).

NOPEC's current supply agreement with Gexa runs through May 31, 2011, but pricing was only locked through December 31, 2010 (18 months from the start), with pricing for the remaining period subject to future negotiations.

Because of the currently favorable wholesale electric market conditions, NOPEC and Gexa wish to obtain electric supply as soon as possible for the remaining five months of the aggregation program, from January 1, 2011 through May 31, 2011, to provide NOPEC consumers with the most advantageous pricing possible.

However, NOPEC and Gexa noted that Ohio Admin. Code 4901:1-10-01(P) and 4901:1-21-01(T) could be interpreted such that the five-month period in 2011 constitutes a separate "aggregation program" under the rules, and thus subject to the minimum 12-month requirement for aggregation programs. If PUCO subscribes to such an interpretation, Gexa and NOPEC asked for a waiver, noting that customers would benefit from allowing NOPEC to set a fixed price for the five months in 2011 now.

NOPEC and Gexa further argued that requiring the 2011 pricing to last 12 months would be

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MISO Proposes to Deduct Retail Rate from LMP Paid to Aggregated Demand Response

The Midwest ISO will pay Aggregators of Retail Customers (ARCs) providing energy injections in the form of demand response the Locational Marginal Price minus the Marginal Foregone Retail Rate, under a MISO proposal filed with FERC to integrate aggregated retail customers into the market per Order 719. MISO asked FERC to approve the changes to become effective June 1, 2010.

Under MISO's proposal, each ARC that reduces load in a given hour in connection with an energy-related offer will initially be paid the average hourly LMP at the Commercial Pricing Node where the associated energy reduction occurred over that hour. To determine the LMPs for the ARC's energy injections, each ARC will be assigned a unique Commercial Pricing Node (CPNode) based on the respective Elemental Pricing Nodes (EPNodes) where the individual retail customers physically withdraw their energy. The LMPs will be calculated at each ARC's CPNode, for each hour, as the average of the LMPs at the EPNodes of the retail customers weighted by their respective demand reductions.

However, at settlement, the Marginal Foregone Retail Rate will be deducted from the LMP payment to the ARC, representing the costs that the retail customers avoided by not paying their utilities/LSEs for the energy the ARC sold at wholesale by offering demand response into the Midwest ISO's energy market, MISO said.

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D.C. PSC Staff Says Hearing Not Yet Needed on WGL Asset Management Practices

Staff of the District of Columbia PSC said that evidentiary hearings on Washington Gas Light's asset management practices, as requested by the Office of People's Counsel, would be premature at this time. Staff made its recommendation in a review of WGL's gas procurement report (FC 874).

Staff agreed that the gas procurement report contains "very little information" on WGL's asset optimization activities and their relationship to WGL's gas procurement activities. However, Staff said that the procurement working group should first address what information on asset management should be included in the report, prior to instituting hearings.

Additionally, WGL's decision to move asset optimization in-house rather than using a third-party to manage assets, "brings new challenges and requires additional review ... and WGL must provide substantial additional information to facilitate the further understanding of its asset optimization activities," Staff said. Staff recommended that the procurement working group address such issues in a written report, including OPC's concerns regarding documentation of the program, accounting for asset optimization transactions, and inventory.

The Maryland PSC currently has an open contested case reviewing WGL's asset management program (Only in Matters, 8/26/09).

Furthermore, WGL has not shown to what extent it actively engages in capacity release transactions beyond the capacity WGL is required to release to competitive suppliers, Staff said. WGL has also not provided sufficient information to allow Staff to understand the relative benefits of capacity release versus asset optimization, Staff added. WGL's assertion that asset optimization is a better approach needs to be substantiated in the next gas procurement report, Staff said.

WGL had said earlier this year that the lack of liquidity in the competitive capacity release market made its self-managed optimization program, which uses bundled transactions in the wholesale market, preferable to straight capacity releases via auction (Only in Matters, 3/19/09).

Staff said that WGL has provided extensive documentation regarding its traditional procurement activities, rejecting OPC's concerns about a lack of information.

FERC Rules NCPC Payments Shall Not Include Fixed Costs

FERC conditionally accepted ISO New England's revisions to Appendix A of Market Rule 1 to address the market power mitigation of offers for resources that are committed to satisfy local and system-wide reliability needs, subject to the outcome of Docket ER09-1051 (which is examining some of the same issues), as FERC found that Net Commitment Period Compensation (NCPC) payments should not include recovery of fixed costs since such costs can be recovered under the Forward Capacity Market or other markets.

FERC said that the proposed revisions reduce the ability and incentives for generators to inflate their bid-in operating parameters (such as their minimum run times), which in the past has resulted in inefficient dispatch.

The Commission disagreed with protests from wholesale suppliers who had argued that the Forward Capacity Market and other locational markets do not provide sufficient opportunity for fixed cost recovery. "We note that fixed-cost recovery was an important consideration and key rationale for FCM. As the Commission has stated, 'if generators wish to participate in the FCM on a long-term basis, the FCM market rules give them an opportunity over time to recover not only going forward costs, but also additional fixed costs and a profit,'" FERC said.

FERC also rejected requests from wholesale suppliers for a transition mechanism in implementing the new mitigation. "We find no reason to delay the implementation of Filing Parties' proposed revisions or to adopt a transition mechanism to phase-in the revisions. We will not allow market participants to continue to exercise market power during a transition period just because the first and second Forward Capacity Auctions have already taken place," FERC held.

The Commission did agree with suppliers that ISO-NE failed to justify its proposal to trigger mitigation if the supply offer exceeds a resource's reference levels by more than the lesser of 10 percent or $80/MW-day. FERC directed ISO-NE to make a compliance filing justifying why the $80/MW-day threshold is appropriate.

FERC Approves CAISO Clarifications on Relaxing of Constraints

FERC accepted the California ISO's tariff filing to clarify the role of the full network model, dismissing protests raised by wholesale suppliers (ER09-1542, Matters, 4/14/09).

Among several tariff changes sought by CAISO is to clarify that, in running the CAISO Markets, the CAISO will establish, enforce (or not enforce as the case may be), and manage the constraints modeled in the full network model in accordance with the considerable detail provided in the business practices manual for the full network model.

CAISO said that the current language erroneously suggests that the constraints are enforced in the full network model, which CAISO said is not the case. CAISO thus proposed changes to more accurately reflect the reality that any enforcement of transmission constraints is conducted through the CAISO markets.

Additionally, CAISO proposed to revise section 31.2.1 of the CAISO Tariff to clarify that only those constraints expected to be enforced in the integrated forward market will be enforced in what is known as the "all constraints run" of the day-ahead market. CAISO proposed this change to make clear that although the CAISO calls this function of the market power mitigation and reliability requirements determination process of the day-ahead market the "all constraints run," not all constraints are enforced at all times. Rather, the CAISO said that the all constraints run enforces whatever constraints are expected to be enforced in the applicable corresponding market run.

Western Power Trading Forum and other suppliers objected to the changes, arguing that CAISO is seeking authority contrary to the purpose of the Market Redesign and Technology Upgrade, which was to move congestion management from real-time to the day-ahead time frame (Matters, 8/25/09).

However, FERC agreed with CAISO that the requested clarifications are not a request for new authority to not enforce all transmission constraints. CAISO's proposed tariff revisions do not serve to change the CAISO's existing authority to relax transmission constraints, FERC said. "While the current tariff language implies that the full network model enforces all transmission constraints, it is clear from the definition and performance of the full network model that such language does not correctly describe the full network model's actual relationship to the enforcement of constraints. Not only does the full network model not operate the CAISO's markets, but, additionally, the February 19 Parameter Tuning Order plainly contemplates circumstances in which the CAISO will relax transmission constraints in order to facilitate the prudent operation of the CAISO transmission system. The relaxation of transmission constraints is appropriately considered by the CAISO's market optimization software in connection with running the CAISO's major market processes, including the integrated forward market, the residual unit commitment, the hour-ahead scheduling process, the real-time unit commitment and the real-time dispatch," the Commission noted.

Despite FERC's approval of the requested tariff language, the Commission shared suppliers' concern regarding the need for transparency regarding manual intrusions in the CAISO's markets, no matter how necessary they may be. "Protesters have provided the Commission with a relatively extensive list of manual actions initiated by the CAISO for which market participants have no specific information, including the relaxing of certain transmission constraints, the non-enforcement of some (but not all) transmission constraints for facilities less than 115 kV, and other constraints that the CAISO has been unable to model. We believe the CAISO and market participants should continue to explore means of improving market transparency and information sharing and that the existing stakeholder process is the appropriate forum," FERC said.

FERC directed CAISO to convene a stakeholder process to address parties' concerns as expeditiously as possible. CAISO has said that it will use the stakeholder process to seek ways in which the CAISO can provide (1) either the list of the constraints that are not enforced in the CAISO market or more visibility into how they are established, and (2) the list of contingencies that are enforced in the CAISO market process.

Suppliers had also argued that the details concerning relaxing, not enforcing and manually adjusting transmission constraints must be included in the CAISO Tariff, citing concerns that the lack of specific information in the tariff may negatively impact parties' ability to participate in the CAISO markets.

Without additional information in the record, however, FERC said that it is unable to discern whether the failure to enforce certain constraints "significantly affects rates, terms or conditions of service."

"Although it would be impractical to list in the tariff all instances in which the CAISO will relax, enforce, or manually adjust constraints, it is reasonable for the tariff to include the general guidelines explaining the CAISO's constraint management practices. This should provide market participants with additional market confidence by providing them with the additional transparency into the CAISO operations they seek, while preserving the CAISO's ability to engage in reasonable operating practices and market management in order to ensure a well-functioning, efficient market," FERC said, directing such issues to be addressed in the required stakeholder process. CAISO was ordered to, through its stakeholder process, develop guidelines for its constraint management process, and submit tariff sheets setting forth those principles that significantly affect rates, terms or conditions within 90 days.

FERC Says Some Tower Refunds Must Include Commission Interest Rate

PJM must pay the Tower Companies the FERC interest rate in refunding certain funds withheld from Tower pending adjudication of a complaint, FERC ruled in an order in response to rehearing requests and a refund report (EL08-44).

PJM had argued that an April FERC order dismissing most of PJM's complaint with respect to allegations of manipulation did not even direct PJM to pay interest on any refunds, let alone pay refunds at the FERC interest rate.

However, the Commission found that Attachment Q, Section VI.A of the PJM tariff specifies that cash provided as Financial Security will be held in a depository account by PJM with interest earned at PJM's overnight bank rate or through other investment options chosen by the participant. For funds that were provided by the Tower Companies as Financial Security, PJM must pay interest in accordance with the requirements of this section of its tariff, FERC said. With respect to all other funds withheld, PJM must pay interest in accordance with section 7.2 of its tariff and the Commission's interest rate.

FERC also clarified that its April order on PJM's complaint did not address PJM's affirmative, common law defense of piercing the corporate veil, and that, under the Arkla doctrine, PJM is not prohibited from litigating that issue in a common law court.

Briefly:

Alberta Government Charges Energy Sales Agent with Fair Trading Act Violations

The Alberta government has charged a door-to-door energy sales agent for using misleading practices to get a consumer to sign a utility contract. Service Alberta said that Dwight Davis, a Calgary-based agent who at the time was marketing for Alberta Energy Savings, is charged with two counts of violating sections of the Energy Marketing Regulation under the Fair Trading Act that deal with making false statements to consumers. The allegations have not been proven in court. Alberta Energy Savings has not been charged, Service Alberta said, as it appears Davis was acting independently. The Alberta government investigated a complaint from a Calgary business owner who signed an energy contract in July, but was concerned about the actions of the salesperson. According to Service Alberta, the salesperson allegedly claimed he was a supplier to utility retailer Enmax and was required by the Alberta government to inspect consumers' bills to ensure they were receiving the "proper" energy discounts. The salesperson allegedly denied he was an energy retailer when questioned and asked the business owner to sign a form that he claimed was to obtain the proper discounts. After signing the form, the consumer realized it was a contract when the salesperson filled in the rate portion of the agreement. The consumer took back the contract from the salesperson and it was never enrolled with Alberta Energy Savings.

Energy Resources Group Seeks Ohio Broker License

Start-up Energy Resources Group LLC applied for an Ohio electric broker license to serve commercial and industrial customers in all service territories. Aside from providing supply procurement, Energy Resources Group said it will also focus on all forms of cogeneration to augment savings through demand side management and governmental incentives. Initially, Energy Resources Group plans to provide engineering and construction management services to ferrous as well as non-ferrous processing facilities. Principal Michael Apgar was a founding partner and COO of New Steel International, which managed large engineering and construction projects in the steel industry. Principal Kevin Carrier was a contracts manager at New Steel International, and previously was an account executive at procurement consultant Cost Reduction Services, and was a founding partner at North American Utilities.

NABA Energy Receives Texas Aggregation License

The PUCT granted NABA Energy an aggregator certificate to serve residential, commercial and industrial customers.

Md. PSC Orders More Constellation Hearings

The Maryland PSC scheduled October 14 and (if needed) October 15 for additional hearings on EDF's investment in Constellation Energy's nuclear unit.

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unreasonable since it is not certain whether FirstEnergy will continue its Standard Service Offer (SSO) in its current form beyond May 2011, nor is it even clear what RTO the FirstEnergy utilities will be located in at that time.

The application of American Transmission Systems Inc. to withdraw from MISO and join PJM, "has created great uncertainty regarding the sources of energy supply, pricing, and continuation of the SSO after FirstEnergy's [electric security plan] expires on May 31, 2011," Gexa and NOPEC noted.

NOPEC and Gexa argued that a waiver should not be necessary, because the administrative rules, "simply do not state that a governmental aggregation program must be synonymous or co-terminus with aggregation pricing periods, or that subsequent pricing periods must each be in yearly increments." Additionally, the Commission's rules specifically contemplate that the supply agreement between the governmental aggregator and the retail supplier defines the term of the aggregation program, and hold that the governmental aggregator can initiate multiple price offerings and opportunities to opt-out during the program, Gexa and NOPEC added,

As such, NOPEC's 23-month aggregation (with one price applicable to the first 18 months and another price for the remaining five months in 2011) meets the administrative code's 12-month minimum term, NOPEC and Gexa said.

NOPEC and Gexa further noted that the basis for the minimum 12 month requirement arguably is to prevent suppliers from serving customers only in lower-cost months, avoiding the higher-cost summer season. "However, having satisfied the minimum one-year requirement, it is unreasonable to require that subsequent pricing periods be in one-year increments. Indeed, nothing prevents a governmental aggregator from establishing an initial 17-month aggregation program from January of one year to May of the next year, encompassing only one summer season, which is the same effect as extending pricing for the NOPEC program to May 31, 2011," NOPEC and Gexa said.

Per its terms and conditions of service, NOPEC will conduct a subsequent opt-out mailing for the five-month period beginning January 1, 2011 and ending May 31, 2011, and customers choosing to opt out of the program may do so without incurring an exit fee.

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The Marginal Foregone Retail Rate will be determined under one of three methods. For ARCs whose participation in the wholesale market was not the result of a specific order from a relevant electric retail regulatory authority, and who are aggregating customers at larger LSEs, the ARC shall specify a Marginal Foregone Retail Rate in its registration with MISO. In this case, both the host LSE and the retail electric regulator will be notified of the chosen Marginal Foregone Retail Rate and will be given an opportunity to protest the selection. The relevant retail regulatory authority will have final jurisdiction on determining the Marginal Foregone Retail Rate.

For ARCs whose participation is the result of specific approval from a retail regulatory authority, or for ARCs in LSEs serving less than 4 million MWh in a year (a cutoff set by FERC in Order 719-A), MISO will use the Marginal Foregone Retail Rate as established by the retail regulatory authority in approving the specific ARC's participation. However, should the retail regulator not specify a retail rate in its order approving the aggregation, MISO would automatically set the Marginal Foregone Retail Rate at zero, meaning the ARC would be paid the full LMP.

MISO said it is appropriate to set the Marginal Foregone Retail Rate at zero in the absence of a specific rate selected by the retail regulator because, "retail ratemaking is a complicated process, with many factors to consider when designing the appropriate rates," which could make the rate positive or negative depending on policy goals. "It is not the matter for the wholesale market administrator to decide on the appropriate rate," MISO said.

MISO noted that several ARCs and large industrial consumers have indicated that they may oppose MISO's proposal of paying energy from demand response the LMP minus the retail rate. "However, most of the other stakeholders have indicated some support for it. It has some favor among the state commissions, [and] therefore [is] the option seemingly least likely to produce prohibitions on ARC participation," MISO said.

MISO stated that subtracting the retail rate is required to "achieve comparability," with other sources of supply. "When a power producer injects energy into the Transmission System, it owns that Energy because it either produced the Energy with its own Generator or purchased it from another source. In contrast, when an ARC injects energy into the Transmission System, it is not actually delivering additional energy, but rather reallocating Energy that is already present in the system, or reducing the need for an incremental amount of MW to support the energy balance. What the ARC is actually selling is the right of a retail customer to consume that Energy at a price set by the customer's retail tariff. Since the retail customer's meter does not record Energy that the customer does not consume, the customer avoids paying for the Energy it has made available for sale by the ARC. Consequently, the ARC should pay for that Energy in order to sell it to someone else," MISO said.

"In reality, the Midwest ISO will be paying the full LMP for the Energy but collecting the avoided purchase price on behalf of the LSEs that rightfully deserve to be paid for delivering that Energy to the retail customers who then made it available for the ARC to sell," MISO added.

The retail rate deduction will only apply to demand resources providing energy. ARCs that provide Regulation or Contingency Reserves will be paid the average hourly Market Clearing Price for that Ancillary Service at the CPNode where the capacity was delivered in that hour. In addition, an ARC may qualify as a Load Modifying Resource under Module E, and, as such, may participate in either the Midwest ISO administered capacity auctions or engage in bilateral transactions for such capacity.

An indicative ARC proposal in April would have left it to the ARCs and LSEs to settle and sort out between themselves the charges and credits that would ensure that an ARC's compensation is net of any retail rates that the retail customers avoided by offering its demand response into the MISO.

However, MISO now proposes that the net compensation paid to an ARC (LMP minus the retail rate) will be directly charged to the utility/LSE whose retail customers produced the demand reductions, and shall be accomplished through the Midwest ISO's Market Settlements process. "[D]emand reduction sold by the ARC is energy that the LSE would have delivered to the retail customer, if not for the ARC sale. If the demand reduction had not occurred, the LSE would have purchased the MW from the wholesale spot market. However, since the demand reduction was sold into that market, the amount sold was not recorded as energy consumed by the LSE, and the LSE was not charged for it. Billing the LSE the LMP minus the [marginal foregone retail rate] for this sold demand reduction is consistent with the LSE's obligation to serve," MISO said.

MISO said that to comply with various communication requirements in Order 719-A, it will notify via email an affected LSE when load served by it is enrolled to participate, either individually or through an ARC, as a demand response resource in the RTO market, including the expected level of that participation for each enrolled demand response resource.

In addition, the proposed ARC provision includes appropriate mechanisms for sharing information about demand response resources to address the concerns raised by certain parties regarding double counting, verification procedures, and deviation charges. MISO said.

The settlement approach proposed by MISO eliminates the potential for deviation charges on LSEs that have day-ahead positions. In particular, any potential Revenue Sufficiency Guarantee charges due to ARC participation are removed by reconstituting the load reduction effected by the ARC back into the LSE's withdrawal volumes, MISO said.

MISO said that it will provide LSEs, on a periodic basis, aggregated summaries of the extent of participation of their retail customers in RTO markets, on a masked basis for confidentiality reasons.

MISO has revised the metering requirements from an indicative proposal filed in April, now proposing to allow hourly metering measurements for energy provision and five-minute metering measurements for contingency reserve provision. Regulation reserve requirements with respect to metering remain unchanged.

The one-to-one relationship between the Host Load Zone and the Demand Response Resource (DRR) asset has also been relaxed. For Demand Response Resources providing energy, contingency reserves, or capacity, the one-to-one relationship has been eliminated. "If the relationship had continued as it is in the current ASM markets, it might have represented a barrier to enhanced participation by ARCs," MISO said. For DRR - Type II assets providing regulation, there remains a one-to-one relationship between the Host Load Zone and the DRR asset.

MISO also replaced the prior forecasting requirements (Load Zone Dispatch Interval Demand Forecast) with measurement and verification protocols, adopting the framework and guidelines used by NAESB.

The Midwest ISO said that an LSE may not register as an ARC for purposes of aggregating the demand response of its own retail customers. An LSE, however, is qualified to aggregate its retail customers under Section 38.5 of the Tariff.