Energy Choice Matters

May 31, 2010

Distribution Providers Say Few Charges Could be Aligned to Dates of TCRF Updates

"[T]here are in fact very few [distribution] rate changes which are discretionary in nature and the timing of which can be easily modified," the joint Distribution Service Providers said in reply comments concerning changes to the frequency and nature of Transmission Cost Recovery Factor (TCRF) updates (37909). The joint DSPs included the AEP companies, CenterPoint Energy, Oncor, and Texas-New Mexico Power.

As only reported by *Matters*, REPs, in their initial comments, urged the PUCT to provide greater certainty regarding the timing of changes in distribution charges other than the TCRF, suggesting that all such changes could be aligned to the proposed March 1 and September 1 dates for updating the TCRF (Only in Matters, 5/19/10).

However, the joint DSPs noted that many of the rate changes cited by REPs resulted from rate cases whose implementation cannot be forecast in advance, as opposed to interim updates whose schedule could be changed. The start date for modifications to other charges -- those more similar to the TCRF -- cannot be easily changed either, the DSPs said. Updates to the Transition Charges (TC) are specified in the PUCT's financing order, or left to the DSP's discretion, "and those Financing Orders cannot be modified," the DSPs said. Similarly, the Commission has determined that annual changes to energy efficiency cost recovery factors are to occur with the DSP's January billing cycle.

While the Commission is free to explore the timing of these other rate changes, the DSPs called such modifications outside the scope of the TCRF rulemaking.

"While REPs may dislike having to implement rate changes with short notice, after eight years in the current market structure, it is assumed that they have developed the processes and procedures in order to timely and efficiently do so. Being able to quickly implement DSP rate changes would appear to be a core function of being a REP, particularly considering that REPs can and do change

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FERC Finds ISO-NE Order 719 Filing Discriminatory Regarding Treatment of ARCs

FERC rejected a compliance filing from ISO New England concerning the aggregation of retail customers (ARC) for demand response, agreeing with EnerNOC that language in the proposed tariff is discriminatory in that it favors host utilities in such aggregation (ER09-1051, Only in Matters, 11/12/09).

At issue was ISO language which holds that assets cannot be registered into the demand response programs if they are comprised of:

"(a) The customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs unless the Market Participant registering the Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource is the Host Utility serving the customers..." or

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Briefly:

Newsome Energy Receives Texas Aggregator License

The PUCT granted Newsome Energy LLC an electric aggregator certificate to pool residential, commercial and industrial customers. CEO Travis Newsome served as sales manager for Reliant Energy's New Home Builder & Multifamily division for six years (Only in Matters, 5/11/10).

North Shore Energy Consulting Seeks Pa. Broker License

North Shore Energy Consulting, LLC applied for a Pennsylvania electric supplier license as a broker/marketer serving all sizes of non-residential customers in all service areas.

Standard Power of America Seeks Conn. Aggregator License

Standard Power of America, Inc. applied for a Connecticut electric aggregator certificate to serve all types of non-residential customers.

DPUC Schedules Hearing on CL&P Metering Charges

The Connecticut DPUC has scheduled a hearing for June 14, 2010, to consider Connecticut Light and Power's proposed adjusted rates and tariffs necessary to provide the following services: (1) processing a customer's change of supplier; (2) off-cycle meter reading; (3) billing; (4) collection services; (5) load data and analysis; and (6) customer service, pursuant to Order No. 3 of the Decision dated January 13, 1999, in Docket No. 98-06-17 and Order No. 5 of the Decision dated January 12, 2000, in Docket No. 98-01-02RE02. Aside from several decreased charges, CL&P sought to raise the Pulse Output metering option fee to $387.99 from $329.23. The Phone Automatic Meter Reading (AMR) without Pulse Output fee would increase to $586.91 from $534.25, and the Phone AMR with Pulse Output fee would increase to $717.99 from $656.66. The residential off-cycle or special meter read fee would be raised to $19.93 from the current $16.20 (Only in Matters, 3/22/10).

Gateway Reports Number of Military Discount Customers

Gateway Energy Services Corporation reported that since launching its military discount program on Veterans Day last year, more than 3,100 customers have enrolled. The military discount program offers a 5% discount of off Gateway's standard monthly variable rate for natural gas and electricity to new and current customers who are active U.S. military and reserve personnel, honorably discharged U.S. veterans, or surviving spouses or parents of U.S. military personnel.

TC Ravenswood Files FERC Complaint to Obtain Reimbursements Related to Fuel Oil Switching

TC Ravenswood, LLC filed a complaint at FERC asking that the Commission order the New York ISO, per Section 4.1.7a of the tariff, to reimburse TC Ravenswood $2.4 million for the unreimbursed variable costs it incurred during June, July, August, and September 2009 to respond to the NYISO's and Consolidated Edison's orders to burn 0.3% Sulfur No. 6 fuel oil in lieu of natural gas for reliability purposes (EL10-70). The NYISO has taken the position that the tariff does not permit reimbursement for three categories of costs TC Ravenswood is seeking: (1) TC Ravenswood's pro rata payments to have barges deliver Fuel Oil to TC Ravenswood facilities, (2) TC Ravenswood's pro rata payments for third-party off-site Fuel Oil tank and barge storage applicable to the days when it was ordered to provide minimum oil burn service; and (3) incremental variable operation and maintenance charges for on-site equipment (e.g., piping, pumps and other facilities separate and apart from on-site storage tanks).

Exelon Names Pardee COO of Exelon Generation

Exelon has promoted Charles "Chip" Pardee to chief operating officer of Exelon Generation. Pardee has been serving as president and chief nuclear officer of Exelon Nuclear and senior vice president of Exelon Generation since 2007.

Pa. PUC Prosecutory Staff Seeking Penalty for CNE Use of MISO RECs for Duquesne Load

The Pennsylvania PUC Law Bureau Prosecutory Staff is seeking to impose an alternative compliance penalty of $45/MWh on Constellation NewEnergy for a shortfall of eligible RECs (or AECs as known in Pennsylvania) for load in the Duquesne Light area, though Constellation says a waiver is justified since it had the requisite RECs in its GATS account, and transferred the non-compliant RECs due to an administrative oversight. Constellation has asked that it be allowed to transfer these Duquesne-eligible RECs into the proper account in lieu of the compliance penalty.

The amount of the shortfall, and thus total penalty Staff is seeking, is treated as confidential. The shortfall relates to Constellation's obligation at Duquesne for the 2008/09 compliance year.

In Pennsylvania, RECs originating from PJM may be used to meet the RPS requirements for load in any distribution territory, regardless of which RTO the load is in. However, RECs originating from the Midwest ISO may only be used to comply with the RPS requirements for load within a utility located in MISO. The shortfall arose because Constellation, due to administrative error, used Pennsylvania Tier I-certified RECs derived from an alternative energy source located outside Pennsylvania but within the control area of the Midwest ISO for its obligations in Duquesne, which is a member of PJM. Specifically, Constellation transferred, through the PJM Environmental Information System, Inc. Generation Attributes Tracking System, Tier I RECs which are eligible for parts of Pennsylvania within the MISO into Constellation's subaccount for meeting its requirements arising from load in PJM areas.

Furthermore, GATS does not notify users whether a REC meets Pennsylvania's non-universal geographic eligibility requirements. In other words, while GATS identified the problem RECs as eligible to meet Tier I compliance obligations in Pennsylvania, GATS does not indicate whether a particular REC is compliant only for certain utilities' service territories within Pennsylvania.

"[T]he mistake was particularly unfortunate given that Constellation, when it made the transfer error, already had in its GATS account (and maintains today) a sufficient number of Tier I certified AECs derived specifically from alternative energy sources located in PJM, which it could have used to satisfy the AEPS obligations at issue in the instant proceeding," Constellation said.

"Since Constellation obtained enough Tier I AECs to satisfy its AEPS requirement for load served in the Duquesne service territory for the 2008/2009 Reporting Year, its administrative error of transferring the wrong Pennsylvania Tier I AECs into a GATS Reserve Subaccount for such AEPS compliance should not be deemed an act of non-compliance," Constellation argued.

Constellation noted that the 2008/09 Reporting Year was the first full Reporting Year in the Duquesne service territory. "It is reasonable to expect participants in the AEPS compliance process to make administrative and technical errors in the early years of AEPS implementation. In fact, even the Program Administrator could not strictly follow every single detail in the AEPS Act and the Commission's regulations," Constellation noted, citing a delay in the provision of the AEPS Compliance Update to Constellation, which should have been provided to Constellation on or before July 15, 2009, but was not provided until July 28.

Constellation argued that under various PUC rules, the Commission may exercise discretion in not imposing the compliance penalty for the shortfall, as Constellation's, "error was purely administrative and did not offend the letter or spirit of the substantive requirements of subsections (b) and (c) of Section 1648.3."

Staff, however, said that, "[t]here is no provision in the AEPS Act that allows EDCs or EGSs to transfer AECs for compliance in a reporting year after the close of the 90-day true-up period," which Constellation is requesting. "The alternative compliance payment amount is strictly defined in the AEPS Act," Staff argued.

NEPGA Seeks Disclosure of Information Related to OOM Determinations

The New England Power Generators Association petitioned FERC to order ISO New England and the internal market monitor to release information regarding the determination of out-of-market (OOM) resources in prior Forward Capacity Auctions, so that "flawed" determinations regarding whether or not a resource was out-of-market can be corrected so as not to impact future auctions (ER10-787).

NEPGA claimed that it does not challenge or seek to reverse in any way the outcomes, including clearing prices, set by past FCAs. However, NEPGA is seeking the information to "correct" what NEPGA considers flawed determinations regarding whether or not a resource was out-of-market in past FCAs, so mitigation can be applied in future auctions.

NEPGA claimed that these past determinations were, "made under an FCM tariff which was not just and reasonable." NEPGA asserted that in setting OOM matters for hearing, FERC "countenanced" that the prior tariff was not just and unreasonable, which is a far cry from FERC finding in an order that the old tariff was, in fact, unjust and unreasonable -- a finding it never made (nor is likely to, as any finding in the matters set for hearing will likely find a tariff provision *is no longer* just and reasonable -- not that the tariff *was not* just and reasonable).

ISO-NE has proposed modifications which would expand the definition of an out-of-market resource, with NEPGA proposing an even more expansive definition, with the issue set for hearing (see Matters, 4/26/10). However, regardless of how out-of-market resources are defined in future FCAs, NEPGA noted that, under the proposed FCA tariff set for hearing, all existing out-of-market resources will, "receive an amnesty and be permanently exempt from OOM mitigation."

"In other words, all the OOM resources which cleared in the first three FCAs, even if they were designated as OOM by the [internal monitor], will for all future FCAs be treated as in-market, even if they fit and continue to fit within ISO-NE's own definition of OOM," NEPGA said. Thus, NEPGA said that these past results must be corrected so that they do not continue what may be considered unjust and unreasonable results under the ultimately accepted tariff.

NEPGA further said that the information on out-of-market bids, which is only held by ISO-NE, is needed to support its claims that Cost of New Entry (CONE) has been "artificially" depressed -- a claim FERC found that generators had not sustained based on publicly available data.

The specific information NEPGA is seeking includes, but is not limited to:

- For each Resource that sought to offer at a price below 0.75 × CONE, the information reviewed by the internal monitor in reaching its determination whether it was in-market
- Whether the internal monitor reviewed any other offers from other Resources to determine if they were uneconomically low, including a review of offers that were at or above 0.75 × CONE and offers from new Resources deemed to be existing for purposes of FCA #1.

FERC Makes MISO Marginal Loss Surplus Refund Mechanism Permanent

FERC accepted, effective April 1, 2010, the Midwest ISO's tariff changes to make the current, transitional methodology used for calculating and distributing marginal loss surplus revenues permanent. The transitional mechanism expired April 1, 2010 (ER10-980).

Under the now permanent methodology, the total surplus is first allocated to each balancing authority area based on the costs of supplying losses to load within that balancing authority area. The surplus amount allocated to each balancing authority area is subsequently further allocated among market participants on a load ratio share basis. MISO said that this methodology should continue because its analysis and FERC's findings in previous orders have shown that this methodology returns the surplus revenues to customers in a way that is equitable and that does not distort the marginal price signals. In addition, MISO stated that its methodology ensures that, "market participants in balancing authorities with the highest losses receive the largest refunds."

In accepting MISO's filing, FERC dismissed protests from Tenaska Power Services and other parties who had argued that MISO had failed to justify the continuation of the transitional refund method as just and reasonable. Tenaska called MISO's methodology inconsistent with FERC's order in *Black Oak Energy, L.L.C. v. PJM Interconnection, L.L.C.*, because in MISO exporters that pay for transmission service are not eligible for marginal loss refunds.

FERC rejected these arguments, and also found that the fact that MISO failed to consult stakeholders regarding the refund methodology is not reason enough to deny finding MISO's filing as just and reasonable.

MISO Seeks to Change Cost Allocation for Operating Reserves

The Midwest ISO petitioned FERC to replace the current Grouped Zonal Method for the allocation of costs of Operating Reserves with a Market Load Ratio Share methodology.

More specifically, Operating Reserves costs would be allocated based on Market Load Ratio Share, excluding Exports in the case of Regulating Reserve costs, and including Exports in the case of Spinning and Supplemental Reserve costs.

"[T]he Load Ratio Share approach avoids the disproportionately larger allocation of Regulating Reserve procurement costs to non-constrained Reserve Zones (i.e., those without binding constraints) under the current Grouped Zonal Method, as described in the ASM Cost Allocation Study. Instead, an allocation based on Market Load Ratio Share ensures that Market Participants are charged the costs of all reserves procured on behalf of their Load and/or Exports," MISO said.

MISO further said that the Load Ratio Share method is consistent with FERC's prior ASM Guidance Order.

Additionally, using the Market Load Ratio Share allocation method would be consistent with certain tariff revisions that the Midwest ISO plans to subsequently file, including changes that would enhance the procurement of Operating Reserves by addressing binding constraints, but that could exacerbate the disproportionate allocation of Regulating Reserve costs to non-constrained Reserve Zones under the current Grouped Zonal Method.

A change is required because the current Grouped Zonal Method fails to trace costs when a constrained zone imports reserves since it assigns all reserve costs to load in the zone where the reserves originate, rather than where they are consumed. In other words, the cost of reserves located in a non-constrained area that are imported into a constrained zone are charged to the non-constrained area, rather than the constrained zone, thereby sending false price signals to load inside the constrained zone because this load will receive part of its reserves for free.

A MISO study confirmed that the current Grouped Zonal Method allocates a lower percentage of Regulating Reserve costs to constrained Reserve Zones that frequently bind on minimum zonal Regulating Reserve requirements. Since such zonal reserve requirements are less than the constrained zones' Load Ratio Share of the market-wide minimum Regulating Reserve requirement, the difference is made up through the clearing of more Regulating Reserves in non-constrained Reserve Zones. As a result, a larger proportion of Regulating Reserve costs is allocated - and thereby shifted - to non-constrained Reserve Zones.

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their prices on a monthly basis for variable and indexed pricing products," the DSPs said.

The joint DSPs also rebutted arguments from various cities with original jurisdiction, who had argued that the interim TCRF mechanism proposed in the draft rule, in which the DSP's proposed adjustment takes effect on an interim basis even if the Commission adjusts it (with the difference later trued-up), is contrary to PURA's mandate that the PUCT certify all rates as just and reasonable. The DSPs argued that, contrary to the assertions of the cities, the interim fuel factor updates used outside of ERCOT are not deemed to be reasonable by the Commission prior to implementation, and the

DSPs further cited other interim rates currently allowed such as bonded rates and Transition Charges which show that interim rates subject to refund are allowed consistent with PURA.

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"(b) The customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs or the Market Participant registering the Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource is, or is acting on behalf of, the Host Utility serving the customers..."

FERC found that the requirements allowing the host utility to register the demand resources even where prohibited by the relevant retail regulator, "go beyond the requirements of Order No. 719-A."

"First, neither Order No. 719 nor Order No. 719-A allow RTOs or ISOs to treat third-party ARCs and utility aggregators differently. But Filing Parties' proposal would result in different treatment. Specifically, the revised provision states that an entity cannot register if prohibited by the retail regulator unless the entity is the load-serving entity. This would allow a utility to aggregate its customers' demand and register in ISO-NE's demand response programs even in the face of an explicit prohibition by a retail regulator," FERC noted.

"This provision goes beyond memorializing in the tariff a restriction established by a Retail Regulator, and in fact creates an exception to such a restriction that benefits the load-serving entity. Such an outcome is prohibited under Order No. 719-A," the Commission added.

Similarly, FERC noted that the language applicable to small utilities allows an aggregator to register demand response customers absent permission from the retail regulator if the aggregator happens to be the load-serving entity or its designee. "This language conflicts with Order No. 719-A, which directed that the retail load of customers of small utilities could not be registered in demand response programs absent the permission of the retail regulatory authority," FERC said.

FERC directed ISO-NE to file a revised compliance filing consistent with its order.