Energy Choice Matters

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# Champion Energy Leaving Large C&I Market in ERCOT

Champion Energy Services is currently in the process of phasing out service to the large non-residential customer class in ERCOT, the REP told the PUCT in challenging part of it non-volunteer POLR designation (35630, Matters, 10/8/08).

Champion challenged Staff's designation of Champion as a non-volunteer POLR for the large non-residential customer class for the CenterPoint territory.

Champion said it currently has contracts with two large non-residential customers in the CenterPoint area that will terminate during the two-year POLR term beginning January 1, 2009. Once those contracts terminate, Champion reported it will not meet the POLR eligibility criteria as set forth in the Substantive Rules.

Champion did not challenge its designation as a non-volunteer POLR for the small non-residential customer class for the Oncor territory.

StarTex Power, designated as a non-volunteer POLR for the small non-residential customer class in the CenterPoint service area, told the PUCT that its original POLR filing did not properly separate its small commercial and medium commercial customers. The corrected data shows that StarTex does not qualify as a non-volunteer POLR for the small non-residential class at CenterPoint, StarTex said.

Constellation NewEnergy renewed its objection to its designation as a non-volunteer POLR for the small non-residential class in the AEP Texas North territory, as well as its revised designation as a non-volunteer POLR for the small non-residential class in the Texas-New Mexico Power territory.

# Dayton ESP Contains Several New Nonbypassable Charges

Dayton Power and Light's electric security plan (Matters, 10/13/08) would contain several new and potential nonbypassable charges, though Dayton said it, "does not propose to recover generation costs in distribution rates."

Nonetheless, Dayton said in prefiled testimony that it was possible it would seek to recover the costs of new renewable energy generation (or renewable generation ownership through contracts) via a nonbypassable surcharge, which Dayton believes is permissible under SB 221.

While initially planning to meet its alternative energy portfolio targets through RECs, Dayton anticipates that in the future it may build or purchase renewable or alterative energy resources, which it will procure through a competitive bid process. Dayton has been working closely with its co-owners Duke Energy Ohio and Columbus Southern at the Stuart generating station to determine the feasibility of installing a 3.8 MW hydropower facility at the site. Dayton is also examining projects using solar energy, biomass energy and wind energy,

"To the extent that DP&L expects to implement new generation that is dedicated to its Ohio consumers, the Company expects that it will seek recovery of such generation project through a non-bypassable charge," the utility said.

Cost recovery of RECs bought on the market would be bypassable.

Another nonbypassable surcharge was proposed for cost recovery of economic development rates and unique arrangements meant to retain industrial load. Although the incentive rates would only be available for customers taking the standard service offer (SSO), Dayton would recover both the delta

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# Virtual Bidders Counter Calls for Change in MISO RSG Cost Allocation

Complainants arguing that the Midwest ISO's current Revenue Sufficiency Guarantee (RSG) cost allocation is unduly discriminatory have not justified their alternate proposals based on cost causation, and ignore the fact that physical load is the beneficiary of the Reliability Assessment Commitment (RAC) process that produces RSG costs, Edison Mission Energy said in a reply brief at FERC in favor of the current RSG cost methodology (EL07-86).

Several load serving entities have complained that the current RSG cost allocation is discriminatory because First-Pass costs are only assigned to entities that actually withdraw energy, even though virtual bids also produce RSG costs (Matters, 9/23/08). After a protracted process, FERC set the matter of alternate proposals for paper hearing.

But Edison Mission countered that Complainants, including Ameren and the Midwest TDUs, have not provided a cost causation analysis that compares the market with and without virtual supply offers, nor do they show what would happen to the level of RSG costs when comparing those two cases.

Rather, Edison Mission said, Complainants, "base their entire case on the assertion that the Commission already found that virtual supplies cause RSG costs in the [earlier] Section 205 proceeding."

"If that were the case, there would have been no reason for the Commission to have this paper hearing," Edison Mission reasoned.

The Midwest TDUs, in arguing for assignment of RSG costs to virtual bids, rely on a "correlation" study that the MISO prepared in connection with its development of a new cost allocation proposal, Edison contended, but correlation cannot be a substitute for causation.

Edison Mission further argued that RSG charges in MISO are "substantially inflated" because the MISO energy pricing software fails to capture the cost of most peaking generation in the real-time locational prices for energy. "This not only means that most of the costs being recovered as RSG are not even true RSG costs, but also that real-time energy prices are below the incremental cost of meeting load," Edison Mission said.

"Rather than having higher energy prices that compensate marginal generators, MISO compensates those generators through RSG payments, which has the effect of reducing the total rate paid by load. If this problem were fixed, the level of both RSG charges and virtual offers would decline," Edison Mission added.

Moreover, until the problem is fixed, any attempt to assign responsibility for RSG based on "cost causation" would be inherently flawed because most of the costs being recovered through the RSG charge are actually energy costs, Edison Mission pointed out.

Edison Mission claimed that eliminating the provision that RSG costs must be assigned to entities actually withdrawing energy, "has no basis in cost causation whatsoever." The "actually withdraws energy" provision was designed to incent load-serving entities to bid their physical load in the day-ahead market, accomplishing an important market design objective, Edison Mission added. Striking the "actually withdraws energy" tariff language is offered as a solution by Complainants, Edison Mission reasoned, "only because it is simple to implement, produces a significant shift of cost responsibility to someone other than the Complainants, and can be used to calculate refunds."

In fact, the proposed RSG cost allocation changes would shift $1.30/MWh of RSG costs to virtual supply offers, Epic Merchant Energy and other financial marketers said. That's three times the $0.41/MWh average profit on virtual trades, financial marketers noted, which would make the virtual market uneconomic.

RSG costs in 2007 were actually 39% lower than average in hours where there was net virtual demand on the MISO system, which comprised two-thirds of all hours in 2007, financial marketers claimed.

E.ON cautioned that any cost allocation modification must follow cost causation principles, and that the effect of eliminating the tariff language "actually withdraws energy" may cast too wide a net and would subject other transactions that have not been shown to cause RSG costs to the same hourly charges. "Specifically, this proposal could result in RSG charges [on] some importing activity even where it has not been determined that such importing activity results in RSG cost incurrence," E.ON said.

MISO does not believe the current methodology is unjust or unreasonable, but is open to changes and previously submitted its "indicative" proposal using four RSG cost buckets. However, MISO objected to the suggestion from the Midwest TDUs to allocate so-called "Second Pass" RSG charges to all Market Participants, not just LSEs.

Second Pass charges are allocated on a load ratio share, and are required when direct assignment of costs results in a revenue shortfall. TDUs reasoned that all market participants should pay Second Pass charges because they all cause RSG costs to some degree since they all benefit from the existence of the markets.

But MISO found the TDUs' argument to be flawed, since, "[c]arried to its conclusion, the benefit-from-the-market argument would impose all market charges on all Market Participants simply because they benefit from the markets, regardless of whether they caused particular types of charges."

The Organization of MISO States supported Complainants' recommendation to remove the "actually withdraws energy" exemption in the current RSG tariff, since the Commission, "already has found that virtual supply offers and generator deviations from schedule cause the Midwest ISO to commit units after the close of the Day-Ahead Market and therefore cause RSG costs to be incurred."

OMS also recommended that FERC resettle the market for the period prior to August 10, 2007, the refund effective date.

## NRG Urges Improvement to NERC TLR Standard

An indefinite delay in resolving the considerable impacts on system reliability caused by NERC's current Transmission Loading Relief (TLR) proposal poses a "significant threat to competition in regions such as Entergy," NRG Energy argued in urging FERC to direct NERC to expeditiously address shortcomings in the current Interchange Distribution Calculator (IDC).

The Interchange Distribution Calculator is used by Reliability Coordinators to identify those transactions to be curtailed in response to a TLR. Specifically, NRG asked FERC to remand proposed Reliability Standard IRO-006-4, relating to TLR standards, back to NERC for further consideration (RM08-7, Matters, 7/4/08).

"Accepting the TLR standards proposed by NERC in this proceeding (and more specifically the flaws therein) would mean approving standards that violate core open access principles," NRG claimed.

According to NRG, the current Interchange Distribution Calculator fails to recognize significant numbers of native load transactions, by, among other things, not utilizing real-time data to calculate internal schedule curtailments. The current system requires entities engaging in interchange transactions to bear a disproportionate share of the system's reliability obligations, NRG said.

NRG also noted there is a gap in the proposed TLR standards that allows certain non-firm transactions to escape curtailment prior to the issuance of a Level 5 TLR -- a "clear violation" of the Commission's OATT curtailment priority rules.

Under the current TLR procedures, a transaction is curtailed only if its impact on the constrained facilities is shown to have a Transfer Distribution Factor (TDF) of 5% or more. Accordingly, if the Reliability Coordinator determines that curtailment of non-firm transactions with a TDF of 5% or more will not fully relieve the constraint, the Reliability Coordinator will initiate curtailment of firm transactions. By allowing non-firm transactions with a TDF of less than 5% to continue to flow, the TLR procedures violate the OATT requirement that all contributing non-firm transactions be curtailed first, NRG said.

While NERC has stated it is making "preliminary efforts" to improve the Interchange Distribution Calculator to more accurately determine the impacts of native load and network service, and promote intra-area redispatch as necessary to support reliability goals, NERC estimates the process will take two to five years.

"Two to five additional years is simply too long for the Commission to wait to address the OATT violations and reliability problems caused by the existing standard, NRG contended.

NRG also observed that significant reliance on TLRs to manage congestion as seen in Entergy is not the norm in other Southern regions of the Eastern Interconnection. For example, TLRs are rarely if ever used in the Duke Power Company or Southern Company balancing authority areas, NRG said. By contrast, the Entergy region makes extensive use of TLRs to manage routine system congestion. "These disparate results occur despite the fact that all Reliability Coordinators are applying the same TLR protocols, but other systems are proactive in ensuring that systems are planned and operated to avoid reliance on TLRs," NRG reasoned.

## *Briefly:*

**CenterPoint Accepting All DNPs**

CenterPoint is now accepting all Disconnect for Non-Pay (DNP) and Re-Connect (R/C) transactions from REPs, including submissions for all residential and non-residential premises, it said in a market notice. CenterPoint also confirmed that it resumed normal meter-reading operations on Monday as scheduled. The enrollment backlog stands at 39,632.

**Centrica, Vphase Explore Bringing Efficiency Products to U.S. market**

Energy efficiency product developer Vphase will collaborate with Centrica to explore how Vphase products could be introduced to the North American home and business services market through Centrica's Direct Energy Services subsidiary, Vphase said in announcing a memorandum of understanding with Centrica's British Gas unit. Among Vphase's products is a voltage reduction and regulation system called VX1, which Vphase claims reduces residential bills 10%.

**Tenaska Affiliate Acquiring Michigan Gas-Fired Plant**

A company managed by Tenaska Capital Management is acquiring the 1,100 MW, combined-cycle Covert Generating Plant located near South Haven, Michigan, in the Midwest ISO footprint from MACH Gen. Independent power producer MACH Gen was formed in 2003 to own, manage and complete construction of four generating plants being developed by Pacific Gas & Electric's National Energy Group.

**AEP Appeals Latest 2009 CSC Designations**

AEP has filed an appeal of TAC's decision on October 8 to approve for 2009 the Commercially Significant Constraints (CSCs), congestion zones, Closely Related Elements (CREs), and boundary generators. FPL Energy had previously appealed the designations (Matters, 9/9/08). The ERCOT Board will consider the CSCs Oct. 21. Stakeholders can file comments on the designations by 3 p.m. Oct. 16.

**Reliant Signs Definitive Agreement With First Reserve Corp.**

Reliant Energy yesterday confirmed it has entered into a definitive agreement with an affiliate of First Reserve Corporation related to Reliant's previously announced commitment for the issuance of $350 million of Reliant convertible preferred stock to First Reserve (Matters, 10/1/08).

## *Dayton ESP... from 1*

revenue (the difference between the SSO rate and the subsidized rate) and administrative costs of such rates from all customers via a nonbypassable charge. Administrative costs would be $750,000, Dayton said.

Dayton would also impose a nonbypassable charge to fund various conservation and energy efficiency programs. Only mercantile customers that implement their own energy efficiency measures under Commission rules could avoid the rider.

The ESP would continue the current nonbypassable Rate Stabilization Charge which is part of Dayton's existing rate plan.

Despite rules contemplating an examination of the ESP's impact on competition, Dayton gives scant mention to the subject. Dayton does not address the impact of nonbypassable charges on retail choice, but does examine the risk that customers returning to bundled service places on the utility and SSO customers. For that reason, Dayton proposed requiring customers returning to bundled service to pay a market variable rate upon their return, rather than the SSO price. Dayton did not specifically state such a tariff would preclude the need for any standby charges.

In more than 1,100 pages of testimony, Dayton also gives limited discussion to the impact of the ESP on governmental aggregation, and merely states that the proposal for market rates for customers returning to utility service does not affect the unavoidable generation charges assessed to customers that take service from a Competitive Retail Electric Service (CRES) Provider pursuant to a large-scale government aggregation program.

Dayton also suggested that it "may become necessary" to develop tariffs to recover the cost of serving Curtailment Service Providers, depending upon their activities in the utility's service territory and upon mandates placed on utilities by PJM to serve Curtailment Service Providers' settlement needs and data requirements.

Dayton opined that Curtailment Service Providers operate independently within and across the service territories of distribution utilities with no requirement to register with the utility or give notice of their activity other than by completing an application with PJM. Utilities are made aware of Curtailment Service Provider activities only when the utility is contacted by the Curtailment Service Provider to request a settlement after a demand reduction.

"The PUCO needs to consider certifying these entities just as it certifies CRES Providers to operate in Ohio," Dayton recommended.

As previously reported, Dayton proposed deferring fuel, fuel-related and purchased power expenses that it incurs from 2009 through 2010 that are not being recovered in current standard service rates until 2011, at which time they would be recovered over 10 years.

Dayton also proposed providing special services including, but not limited to, the following:

- Designing and constructing customer-owned electric facilities;
- Addressing power quality issues on customer equipment;
- Performing customer equipment maintenance;
- Providing entrance cable repair;
- Disconnecting and refastening customer-owned equipment; and
- Providing restorative temporary underground service.

Dayton's tariff would state that no approved special services could be provided to the customer until Dayton first notifies the customer that other suppliers may supply the same service.

Dayton is a 4.9% shareholder in the Ohio Valley Electric Corporation (OVEC), but its investment in OVEC is not currently in its ratebase. Dayton does not own any of the generating assets of OVEC but rather has the contractual right to receive electric power from OVEC proportionate to its shareholder interest. Dayton intends to transfer those contractual rights to merchant affiliate DPL Energy. Dayton also intends to transfer three peaking units with a nominal capacity of 240 MW (the Tait units) that are not currently in the ratebase to DPL Energy as well.