Energy Choice Matters

June 1, 2010

Market Participants Discuss Concerns Over Possible Unexpected Charges Under Nodal

Market participants have asked the PUCT to provide guidance on what types of charges resulting from the change to a nodal market may be passed through to customers on fixed price contracts, during a Friday meeting hosted by the PUCT to discuss the interaction of the nodal market and REPs.

The nodal market may result in several costs not expected by REPs under the zonal system, such as the basis risk between trading hubs and load zones and unanticipated increases in Reliability Unit Commitment (RUC) costs. The question is, since such costs would not have been incurred but for the implementation of a nodal design, do they fall under one of the exemptions allowing a change in the rate of a fixed price contract for those customers under 50 kW for whom the PUCT has set a strict definition for a fixed price product.

Specifically, for such small volume customers, a fixed price is defined by rule as, "[a] retail electric product with a term of at least three months for which the price (including recurring charges) for each billing period of the contract term is the same throughout the contract term, except that the price may vary from the disclosed amount solely to reflect actual changes in the Transmission and Distribution Utility (TDU) charges, changes to the Electric Reliability Council of Texas (ERCOT) or Texas Regional Entity administrative fees charged to loads or changes resulting from federal, state or local laws that impose new or modified fees or costs on a REP that are beyond the REP's control."

Wholesale suppliers, REPs, and brokers all asked whether charges that would not arise but for the change in market structure to nodal would fall under the category of, "changes resulting from federal, state or local laws that impose new or modified fees or costs on a REP that are beyond the REP's control." Although not discussed by market participants, the issue of whether a charge is "recurring" may be another area where clarification would be useful. Per the rules, a recurring charge is a charge for a retail electric product, "that is expected to appear on a customer's bill in every billing

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Pa. Marketers Recommend Monthly Electric Default Service Rate Changes

"[U]tility default service pricing for residential and small commercial customers should be a monthly-adjusted, market-based commodity rate and reflect a utility's fully allocated, embedded and projected stranded cost," the Pennsylvania Energy Marketers Coalition said in comments on the Pennsylvania PUC's electric default service rulemaking and policy statement (L-2009-2095604, M-2009-2140580).

The Pennsylvania marketers include Agway Energy Services, Energy Plus Holdings LLC, Gateway Energy Services Corporation, Interstate Gas Supply, U.S. Gas & Electric, and Vectren Retail.

"Market-based, default utility service rates which are adjusted monthly will ensure just and reasonable rates for consumers, entail minimal regulatory oversight, and cultivate a market environment in which effective competition can flourish. Monthly adjustments to EDCs' default service pricing are essential to an efficient electricity market in the Commonwealth because they will

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Briefly:

Energy Plus Holdings Receives Md. Electric License

The Maryland PSC has granted Energy Plus Holdings LLC an electric supplier license to serve residential and commercial customers at the four investor-owned utilities, Choptank Electric Cooperative, and the Southern Maryland Electric Cooperative (Only in Matters, 1/14/10).

WhiteFence Launches Pa.-Specific Site

WhiteFence has launched a Pennsylvania-specific site for its online brokering of Pennsylvania electric load branded as PowerPennsylvania.com. Suppliers currently offering electricity through the site include Champion Energy Services, Gateway Energy Services Corp., and MXenergy. Currently, only service within PPL is offered.

FERC Grants Delegated Authority to Office of Energy Policy and Innovation

FERC has amended its regulations to allow its Office of Energy Policy and Innovation to receive delegated authority to process routine, uncontested, and non-controversial matters. FERC said that this delegated authority will allow the Office of Energy Policy and Innovation to carry out its mission of, "provid[ing] leadership in the development and formulation of policies and regulations to address emerging issues affecting wholesale and interstate energy markets."

Energy Choice Matters published an issue on May 31. Stories included:

- Distribution Providers Say Few Charges Could be Aligned to Dates of TCRF Updates
- FERC Finds ISO-NE Order 719 Filing Discriminatory Regarding Treatment of ARCs
- NEPGA Seeks Disclosure of Information Related to OOM Determinations
- FERC Makes MISO Marginal Loss Surplus Refund Mechanism Permanent
- And more

National Grid Proposes Eliminating Threshold in Critical Day Language

National Grid has proposed modifying its Massachusetts distribution service terms and conditions to change the critical day language found in Section 11.6 to remove the current percentage threshold, as part of its current gas rate case (Docket 10-55).

Under the current tariff, for a Critical Day Aggravated by Underdelivery, a supplier is charged a penalty of 5 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceeds 102% of the supplier's aggregate actual receipts on the Delivering Pipeline to the Gas Service Area.

Per the proposed Critical Day Aggravated by Underdelivery tariff, National Grid would remove the 2% threshold, with the new language stating that, "[t]he Supplier is required to match the upstream pipelines balancing threshold. Failure of the Supplier to match this threshold will result in the Supplier being assessed a penalty of 5 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceeds the Supplier's aggregate actual receipts on the Delivering Pipeline to the Gas Service Area." A penalty of 0.1 times the Daily Index for the differences between said receipts and said usage that exceed 20% of said receipts [(Receipts - Usage) > (20% x Receipts)] would not be changed.

Similarly, for a Critical Day Aggravated by Overdelivery, the current tariff holds that a supplier will be charged a penalty of 0.1 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceeds 120% of the Supplier's aggregate actual receipts on the Delivering Pipeline to the Gas Service Area.

The proposed tariff would strike the 120% threshold for Critical Days Aggravated by Overdelivery, holding that, "[t]he Supplier is required to match the upstream pipelines balancing threshold. Failure of the Supplier to match this threshold will result in the Supplier being assessed a penalty of 0.1 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceeds of [sic] the Supplier's aggregate actual receipts on the Delivering Pipeline to the Gas Service Area." A penalty of 5 times the Daily Index for differences between said receipts and said usage that exceed 2% of said receipts [(Receipts - Usage > (2% x Receipts)] would not be changed for Critical Days Aggravated by Overdelivery.

Elkton Gas Submits Changes in Calculation of PGA to Minimize True-Ups

Elkton Gas has petitioned the Maryland PSC to modify the Purchased Gas Adjustment clause in its tariff to (1) utilize a more current market gas cost rate, (2) employ rate stability, and (3) minimize swings in prior period true-ups. "The Company believes the proposed changes will be beneficial to its customers as it will provide them with greater rate stability, minimized size of gas cost true-ups, and a more current market based price signal."

Elkton does not currently offer a residential choice program but does offer non-residential choice, though supplier participation is non-existent.

Currently, the PGA is calculated using information that is, at best, two months old, based on actual contractual and accounting gas cost information for a rolling 12 month period, which is multiplied by rate factors obtained from the most recent supplier bills. Such rates include gas, pipeline, and storage costs as well as off-system sales credits.

Under Elkton's proposed changes, the Gas Cost Component of the PGA would instead be determined using a combination of forecasted market rates and actual fixed supplier and storage costs for the upcoming period, as opposed to using outdated historical rates.

More specifically, the Gas Cost Component would be determined using a weighting of gas costs from supply sources of flowing gas and any fixed price gas and/or storage gas forecasted for an upcoming calendar quarter. The forecast price for supplies not covered by fixed price or storage gas costs would be based on forward looking prices sourced from NYMEX, set within three business days of the upcoming PGA period.

Remaining parts of the PGA would be set annually, including:

- Capacity Cost Component, consisting of Elkton's total estimated annual fixed pipeline costs, fixed supplier costs, and fixed storage costs
- Off System Sales, consisting of Elkton's estimated credits for asset manager fees, off-system sales and/or exchange of gas
- Supplier Refund Adjustment, consisting of refunds received from suppliers
- Actual Cost Adjustment, consisting of any over- or under-recoveries in the PGA from a prior period
- Distribution Taxes, consisting of any taxes, assessments, or similar charges that are lawfully imposed on Elkton for procurement and/or sale of gas

The capacity and off-system sale components are modified in the proposed tariff to be based on a forecasted outlook instead of historical costs or credits.

Elkton said that its intention is to set the PGA on a quarterly basis, but that it also reserves the right to file monthly rates under certain circumstances. Elkton said that monthly rates would only be used to mitigate imbalances and to send proper pricing signals to customers in the event of unexpected, substantial market volatility in gas costs or unforeseen changes in other PGA components which were initially set as an annual rate. Examples of such scenarios include excess market supply, supply disruptions, or changes in pipeline rates.

SPP Recommends Triggering Offer Cap In Cases Of Temporary Flowgates

The Southwest Power Pool's internal market monitor reported that the Energy Imbalance Service (EIS) Market saw "good health" for 2009, though the internal monitor offered several recommendations to improve the market, in a 2009 state of the markets report.

A key recommendation concerns the triggering of offer caps when flowgates are activated. Currently, the market system imposes offer caps on resources that have the potential to wield market power when permanent flowgates are activated. The offer cap system also only uses congestion on permanent flowgates in calculating individual caps.

The original design for the offer cap system did not include temporary flowgates because they represented a very small portion of the total number of flowgates, and they had a very short life expectancy. However, temporary flowgates have become a significant source of congestion, the monitor noted. "To address this change in system operations, the reference to permanent flowgates in the market protocols should be removed and the offer cap system should be modified to include temporary as well as permanent flowgates. These changes would ensure that the offer cap system effectively caps offers over time regardless of the use of temporary flowgates," the monitor recommended.

Furthermore, the current trigger for activating a flowgate is Transmission Loading Relief (TLR), as SPP uses TLRs as a proxy for congestion. While historically TLRs have been a good proxy for congestion, the monitor noted that proposed market rule changes would allow SPP to activate flowgates for extended periods without calling a TLR. "SPP needs to develop a new trigger for imposing offer caps to reflect actual congestion before implementing any rule changes with regard TLRs," the monitor recommended.

Other recommendations include moving quickly to standardize categories that account for transmission outages, in order to allow easy reporting on the causes and locations of transmission outages across the footprint. Additionally, the monitor recommended that SPP should monitor and report trends in transmission congestion and the use of temporary flowgates.

The internal monitor reported that even assuming a perfect dispatch response throughout the year, the energy imbalance market would not have yielded sufficient revenue in 2009 to warrant investment in new generation, for both natural gas-fired peaking turbines and intermediate load combined cycle units. "This is not surprising, given the relatively high installed resource margin ... and the significant drop in electricity prices in 2009," the monitor noted.

In 2009, overall EIS Market sales were roughly equal to 10.6% of total electricity consumption within the EIS Market footprint. On average, 88% of installed resource capacity was made available for dispatch in the EIS Market.

The average portion of available capacity made available for dispatch (the average dispatchable range) was 44% (versus 46% last year). "This decline concerns us, and as a result we are looking at this metric at the market participant level regularly," the internal monitor reported.

Furthermore, the average ramp rate for 2009 was 2.8 MW/minute, the same level as in 2008. "This level seems low, and is a concern of ours. The average ramp rate had increased in late 2008/early 2009, and we thought that the reason for that increase was a rule change made in October 2008. This rule change allowed a participant to break up its dispatchable range into as many as 10 segments and to provide a different up and down ramp rate for each segment. However, ramp rate has since declined, reaching a low of 2.6 MW/minute in December," the monitor added.

The monitor also expressed concern regarding the trend of increasing transmission outages in each of the past three years. Even if when removing new balancing authorities added in 2009 from the calculation, transmission outages increased 45% when compared to the 2008 total. This increase follows increases of 39% from 2006 to 2007 and 5% from 2007 to 2008. "This increasing trend concerns us. We believe that part of the reason for this increase is most likely due to legitimate reasons such as the increased amount of transmission investment that has resulted from SPP's Transmission Expansion Plan (STEP). However, given the current data set, we are unable to confirm this and other hypotheses," the monitor said.

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period or appear in three or more billing periods in a twelve month period." Could a REP argue that a one-off anomalous charge resulting in the first month of nodal, perhaps due to implementation "teething" issues, is a non-recurring charge that thus was not included in the fixed price, and may permissibly be added to that month's bill?

Market participants noted that during the Load Frequency Control (LFC) test, there was a significant separation between the hub price and load zone price for Houston due to transmission (an autotransformer being out of service), with prices of $(3)/MWh at the hub and $35/MWh at the load zone.

Currently, nearly all trading is done at the hub price, and thus REPs would only be hedged at the hub price. Even when hedged at the hub price, REPs are still exposed to significant basis risks as seen by the LFC test, however.

For customers above 50 kW not subject to the Substantive Rules' definition for fixed price, REP contracts are generally being drafted to give REPs the broadest possible ability to pass through unanticipated charges resulting from nodal operations. Brokers asked that, while acknowledging REPs may permissibly pass through such costs, such costs should be identified for customers as a line item on bills (e.g. a line item for RUC costs) so customers understand why they are not receiving their expected fixed price in a given month.

REPs are also concerned with the levels of expected RUC costs since such costs will impact their credit requirements.

In response to questions from REPs, ERCOT COO Mike Cleary said that, in the market trials, prices are averaging $25/MWh to $35/MWh, although scarcity prices have been seen. Cleary said that the scarcity results are driven more by the lower quality of the data submitted rather than actual expected strategies and outcomes under nodal. Cleary stressed that the outcomes at this point are not meaningful as most generators will not submit their actual bidding strategies until real money is in play, for fear of revealing their strategies. As a result, the market trials are seeing "appalling" RUC solutions (125 resources committed as RUC in one recent operating day), since generators are not updating their Current Operating Plans (COPs). Cleary said that the 168-Hour test to begin in September will provide more meaningful results in terms of market outcomes.

Cleary said that in recent trials, 54,000 MW participated in the day-ahead market, with up to 220 QSEs of 286 eligible QSEs participating in the voluntary market. On average, the day-ahead market is now seeing 190-200 QSEs participating, up from 175 QSEs several weeks ago.

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encourage a large number of competitive offers from innovative EGSs," the Pennsylvania marketers said.

"While the Commonwealth's default service regulations should provide a backstop for consumers who choose not to take advantage of electricity competition, any default pricing mechanism should not be construed as price guarantees or long-term supply contracts. A move in that direction, as shown in other states, would ultimately work to the disadvantage of consumers because of the inevitable commodity price distortions and lack of price transparency that would occur in a pricing mechanism that does not promote true market-based prices. In addition, artificial price guarantees that are the result of subsidized regulatory constructs - and which will ultimately require cost recovery by the utility in later years - do not provide timely price signals of the market cost of power for consumers," the marketers added.

Consistent with Act 129, the PUC's proposal would delete the old standard that default service must be designed to acquire electric generation supplies at prevailing market prices, and instead require the use of a "prudent mix" of (a) spot market purchases; (b) short-term contracts; and (c) long-term (5-20 year) contracts. Act 129 also confirms that generation rates for residential and small business customers shall change no more frequently than quarterly, which would be reflected in the updated PUC rules (Only in Matters, 1/20/10).