Energy Choice Matters

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NiMo Says Hourly Pricing Not Creating Reduced Demand, Recommends Deferral of Any Expansion

The New York PSC should defer any expansion of Mandatory Hourly Pricing (MHP) to a greater number of customers at Niagara Mohawk because the recent expansion to SC-3 customers above 500 kW has not created significant demand reduction at the time of system peak for New York, NiMo said in a report on the programs.

Expansion of the MHP class at this time would not result in greater amounts of load reduction, based upon NiMo's recent history with the latest expansion of the MHP tariff, NiMo said. "Without customer response, the cost of expansion will be too great," NiMo argued. NiMo instead recommended that it be allowed to analyze tariff changes regarding capacity costs to remove muted price signals.

NiMo expanded the MHP class to SC-3 customers above 500 kW in September 2006, and summarized results from two years of experience with the program in a report to the PSC. The analysis shows that response to prices during the peak is, "limited," NiMo said.

NiMo cited the lack of adequate price differentiation between very high load hours and hours with much lower loads on different weekdays for the lack of load response. Part of the problem lies with the nature of the energy market within the NYISO and the reliance on natural gas, particularly in the colder months of the year, which means prices are higher in the winter despite the summer peaking nature of the system. Another problem is the current allocation of capacity costs, which dilutes the strength of the price signal from capacity costs over more hours than is

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Lower Pricing, Higher Purchased Power Costs Weigh Adjusted Results at EFH

Net loss at the competitive segment of Energy Future Holdings, which includes retailer TXU Energy and generator Luminant, grew to $8.9 billion, from a net loss of $523 million a year ago, mainly on an $8 billion impairment charge related to goodwill.

Excluding the impairment charges, as well as unrealized hedging losses, lower retail pricing and higher purchased power costs were the major drivers of the results. TXU's 15% price reduction, a commitment made during the EFH leveraged buyout phased-in during 2007, decreased results by $85 million versus the year 2007. Higher purchased power costs from volatile demand during the year contributed to another $80 million in lower

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Pepco Mulling Strategic Alternatives for Retail Supply Unit

Pepco Holdings is conducting a strategic analysis of the retail energy supply portion of its Pepco Energy Services unit, executives disclosed on a conference call discussing previously released earnings (Matters, 3/3/09).

The analysis, ongoing for several months, includes an evaluation of potential alternative supply arrangements to reduce collateral requirements, or possible restructuring, sale or wind down of the business. The parent is considering the return it earns on its invested capital in the retail energy supply business versus alternative investments.

The review does not include the energy services side of the retail unit, which Pepco expects to keep.

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World Energy Solutions Trims Yearly Loss

World Energy Solutions narrowed its yearly loss to $6.8 million in 2008, versus a loss of $8.6 million in 2007, on record revenues. Net loss for the fourth quarter was lower at $1.0 million, versus a net loss of $5.2 million in the year-ago quarter, on a 6% increase in revenue and lower income tax expenses.

Yearly revenue was $12.4 million versus $9.2 million for 2007. Gross profit for 2008 was $7.9 million versus $6.3 million a year ago.

During a conference call, executives reported "robust" renewal of Energy Gateway customers acquired in 2007 as part of World Energy's acquisition of the broker. Natural gas business at Energy Gateway has been particularly strong in the first quarter of 2009, executives added. Executives also confirmed that customers, especially governments and municipalities, are returning to longer term deals from two to five years as commodity prices fall, versus the shorter deals World Energy was executing early in 2008.

World Energy's wholesale client basis more than tripled during the year to 39 from 12 a year ago, while the broker also saw record retail bookings. Its annualized backlog grew 20% to $9.1 million in 2008.

Risk of Regulatory "Hold-Up" Preventing New Generation, Stoddard Says

Long-term contracts are not needed to build new generation, and any lack of new build can be blamed on regulatory "hold-ups," Robert Stoddard, Vice President at CRA International, said in a paper released during a Compete Coalition briefing yesterday.

In a study reviewing similar industries, including natural gas, petroleum, and airlines, Stoddard noted the electric industry is characterized by numerous undifferentiated buyers that precludes the need for long-term contracts for new generation.

Noting a "perceived" under-investment in building new power plants in some areas, Stoddard said prospective new investors in power generation face a potential "hold-up" problem from regulators, who can insist on prices that are sufficient to cover the supplier's short-run costs but which deny the supplier an adequate return on its sunk investments. The supplier, with a fixed asset that has little value outside of serving its immediate location, has little alternative in pricing, Stoddard said.

Since a regulator is free to adopt pricing or other rules that make the business case for investing in generation appear attractive, only to behave opportunistically and change these rules later to serve the short-term interests of other parties or the regulator itself, potential generation investors are not likely to invest unless they can be reasonably sure that they will have access to income streams that are reasonably secure against "regulatory expropriation," Stoddard said.

"The recent history of the electric power industry suggests that the problem of regulatory hold-up is far from an academic problem," Stoddard added, noting the imposition of bid caps in ISO New England. Such caps prevented investors, who had made decisions based on the ability to recoup their outlay over time through high spot prices during scarcity conditions, from recovering their costs. "Indeed, this was a contributing factor to the bankruptcy of several of the large IPPs in the early 2000's," Stoddard said.

Compete also presented two analyses showing the problems with pay-as-bid pricing in RTOs, authored by Professor Ross Baldick of The University of Texas at Austin and Dr. Roy Shanker, a market consultant. Pay-as-big pricing has been touted by load groups as superior to single-clearing price auctions, though APPA has now moved to advocating for a balancing market with cost-based offers.

Baldick cited inefficient dispatch; difficulty of participation for small, competitive asset owners; the reduced ability of demand response to mitigate market power; and difficulties for market monitoring as drawbacks of pay-as-bid pricing.

Small market participants face greater costs in the assessment required to form their offers in a pay-as-bid market than the assessment required for offers in a single price market, Baldick noted. In a pay-as-bid market, a small market participant must predict the market-clearing price in order to maximize its profits, requiring considerably greater market knowledge (and thus costs of analysis) than simply offering at marginal cost. However, large market participants can spread the costs of forecasting market-clearing prices across a greater amount of sales than can small market participants. "Consequently, pay-as-bid tends to favor larger market participants, whereas single price allows smaller market participants to 'free ride' on the market analysis of larger market participants," Baldick said.

Since entry by small players mitigates market power, the increased costs to small participants under pay-as-bid may increase market power, as small competitors either exit or cannot enter due to high transaction costs.

Furthermore, Shanker added that under pay-as-bid, market participants essentially try to guess the clearing price. This behavior makes the exercise of market power virtually impossible to detect, since one cannot distinguish between a “bad guess” as to the likely market clearing price, and economic withholding.

APPA Protests PJM All-or-Nothing Demand Response Proviso

APPA protested PJM's tariff filing to implement FERC's Order 719, which clarifies the ability of aggregators of retail customers (such as curtailment service providers) to participate in RTO-run demand response programs and markets. Order 719 permits retail customer participation in RTO load response so long as participation is not barred by the relevant retail regulatory authority.

As only reported in Matters, PJM's proposal, among other things, would require that the relevant regulatory authority either permit all end users of a certain class to participate in load response, or prohibit all such end users. PJM's proposal would not allow retail regulators to certify some customers for RTO participation on a one-off basis, while retaining authority to deny similar applications (Matters, 2/11/09).

APPA says that the "all-or-nothing" proposal contradicts FERC Order 719, which APPA says granted deference to retail regulators without requiring an all-or-nothing approach. The Southern Maryland Electric Cooperative agreed, arguing that Order 719 permits aggregated retail customer participation except where the retail authority does not permit, "a retail customer to participate." SMECO noted the use of the singular phrase "a retail customer" indicates Order 719 permits retail regulators to allow participation of only some specific customers, but not others, since FERC could have used the terms "any" or "all" retail customers.

PJM's proposal would effectively prohibit munis and co-ops from contracting with a single curtailment service provider to act as aggregator and barring end-user participation outside of that selected provider.

Such a limit on competition in customer aggregation is necessary, APPA asserted, because otherwise independent curtailment service providers could “cherry-pick” the demand response potential of specific retail customers, and correspondingly reduce the savings to the customers of the public power system accruing from such programs.

Maine IOUs See Implications from MISO Market Service Decision on Future with ISO-NE

FERC's recent decision denying the Midwest ISO's Market Coordination Service proposal will undoubtedly have implications for Maine's pursuit of reforms at, or an alternative to, ISO New England, Central Maine Power and Bangor Hydro-Electric said in updates on their pursuit of reforms (2008-156).

In a January decision, the Maine PUC instructed the utilities to pursue various reforms at the ISO, but noted that leaving the ISO as a full member, while only taking some services as *a la carte*, may be an alternative if reforms aren't forthcoming (Matters, 1/19/09).

The MISO Market Coordination Service proposal would have extended the benefits of LMP markets to transmission owners who retained operational control of their grids. Among other things, FERC found that such a market design could prompt current transmission-owning members of MISO to exit, thus recreating pancaked rates (Matters, 2/20/09).

"These same concerns would permeate FERC's consideration of a Maine Transmission Owner/ISO-NE Contract Option, or any similar option (such as a NMISA/ISO-NE hybrid) that attempts to selectively tap the benefits of ISO-NE by contract while performing certain functions outside ISO-NE's 'footprint'," CMP said.

"[T]he MISO decision sends clear signals that FERC will not allow ISO-NE to implement rules that could weaken the performance of its RTO functions," CMP added, while BHE concurred that, "FERC's decision reflects its strong policy favoring full RTO membership."

BHE also said that absent FERC approval, utilities cannot take limited services from RTOs. Indeed, CMP cited testimony from the ISO at a recent legislative hearing, in which the ISO reported that FERC will not allow ISO-NE to offer a subset of its services on an individual basis to Maine's utilities. An option to purchase such services must be available to all regional entities on a non-discriminatory basis pursuant to a general tariff provision that must be vetted and approved by ISO-NE's regional stakeholders, CMP said.

"Based on this development, it may be desirable to not only question ISO-NE on its willingness to consider the Contract Option, as required by the Commission's January 16 order, but to also raise the matter with NEPOOL to gauge the organization's willingness to adopt such a general tariff provision," CMP noted.

As to negotiations on improving the current ISO dynamic, CMP reported that other than in the context of discussions of economic transmission upgrades, to date there has been no regional consideration of altering New England's transmission cost allocation methodologies.

"Given the very high level of attention currently given to consideration of economic upgrades, CMP believes that there will be very little regional interest in exploring alternative cost allocation schemes for reliability upgrades until progress has been made on the more immediately pressing [economic] issues. As noted by the Company ... this is not necessarily an undesirable prioritization of regional reforms, given the immediate and substantial needs for reliability upgrades in Maine," CMP said.

CMP also observed that there appears to be "meaningful evidence" of achievable reform in terms of ISO-NE governance, given a working group's focus on modifying the ISO-NE's operating principles, or "mission statement," to include greater consideration of consumer costs in ISO-NE decision making, as well as consideration of greater consumer advocate background for board nominees.

ISO-NE Must Refund Bid Mitigation Settlement Costs to Virtual Trader

A FERC arbiter ordered that ISO New England should refund $725.42 plus interest to virtual trader Lavand & Lodge LLC for improperly assessed bid mitigation settlement charges imposed on the marketer (EL09-8).

The $2 million settlement, approved by FERC in September, resolved claims relating to the former bid mitigation agreements, which paid certain generators above-market costs for reliability reasons (Matters, 6/2/08).

The arbiter ruled that imposing the settlement costs on Lavand & Lodge was unjust and unreasonable since Lavand & Lodge had no involvement with the bid mitigation agreements at issue in Docket No. EL01-93, and was not a market participant from 2001-03 when the bid mitigation proceedings occurred. The settlement spread costs to market participants who were NEPOOL members as of November 2007, but, "[d]etermining settlement liability based solely on November 2007 ISO New England market participation is unjust, unreasonable and inequitable insofar as Lavand & Lodge is concerned," the arbiter said.

"Imposing settlement liability on Lavand & Lodge for litigation risks unrelated to its actual market participation is unjust, unreasonable and inequitable," the arbiter added.

The arbiter noted that Lavand & Lodge had never been served with a copy of the settlement or related filings, even though ISO New England said all parties covered by the pact had been served. Service was only provided to current NEPOOL members and parties to the original bid mitigation dockets, but Lavand & Lodge had terminated its NEPOOL market participant status in early 2008 and was not a party to the earlier dockets; thus it was not served.

Since it was not served with the stipulation, Lavand & Lodge was not prevented from seeking redress due to time limits on intervention and rehearing of the September order, the arbiter said.

Briefly:

Suez Signs City of Hidalgo

Suez Energy Resources NA has signed a contract with the City of Hidalgo, Texas, to provide its electricity through January 2011.

AEP Ohio Says ILR Registrations Not Delayed

AEP's Ohio utilities say they have provided, or are in the process of providing, requested customer load data needed for the PJM Interruptible Load for Reliability registration process, answering a motion filed by Integrys Energy Services (Matters, 2/27/09). AEP says letters sent to customers have contained the needed peak load contribution data, though the letters do inform customers that AEP does not agree to the customer's retail participation in the PJM programs. However, that statement does not preclude PJM from accepting the registration, AEP said. AEP also informed customers in the letter that its opposition to such retail participation in the ILR program is pending at PUCO, as AEP again asserted existing tariff terms and conditions prohibit such "resale" of energy by a retail customer. Contrary to Integrys' suggestion, AEP's actions have not resulted in rejection of any registrations, AEP claimed.

ABATE Appeals Energy Optimization Surcharge

The Association Of Businesses Advocating Tariff Equity (ABATE) has appealed the Michigan PSC's decision imposing an energy optimization surcharge to fund efficiency programs on all customers to the state Court of Appeals. ABATE believes legislation allows transportation-only natural gas customers to avoid such charges where they self-implement efficiency programs (Matters, 2/4/09, 1/7/09).

Brodsky: New York Prices Would be 10% Lower Under Cost-of-Service

New York Assemblyman Richard Brodsky said yesterday that customers would save $2.2 billion from a return to cost-of-service generation, equaling about a 10% reduction in residential bills, citing a report by Robert McCullough. The report was released in advance of a Thursday hearing on Brodsky's bill 1563, which would abolish a market-clearing price, which died in committee last year. Though some reports have Brodsky touting pay-as-bid pricing, the McCullough report advocates the APPA model of a cost-based balancing market, with consumer supplies returned to "fully allocated, cost-of-service electric generating plants."

NiMo MHP *... from 1:*

necessary, NiMo said.

Day-ahead wholesale electricity prices have been "relatively modest" in upstate New York over the past five years, with the exception of the aftermath of Hurricane Katrina in the fall of 2005, NiMo said. While the average price of electric commodity has risen over time, the hourly price in the NiMo Capital Region has rarely risen above 15 cents/kWh. Even then, the run-up in price has been relatively short-lived and the price has never exceeded 21 cents/kWh.

Notably, the run-ups in day-ahead prices that do occur generally don't coincide with the system-wide peak in electricity use. While the New York State electricity system consistently peaks in the summer months, day-ahead electricity prices in upstate New York generally peak during the late afternoon and evening hours of the winter months, driven by spikes in the price of natural gas.

The current treatment of capacity in the MHP tariff is another reason for muted price signals, NiMo said. Since generators must agree to bid into the Day Ahead market for energy in order to receive capacity payments, energy prices are decreased, and the cost of peak load is not reflected to customers.

NiMo identified several possible alternate rate mechanisms to reflect the cost of peak load. A capacity tag could be applied to a customer based upon its demand at the time of the previous year's New York system peak, similar to an approach at NYSEG. The capacity tag would act like a traditional 12-month demand ratchet, and customers with higher tags will have higher monthly capacity bills.

"The possibility of a high demand charge in each month of the following year will keep customers focused on lowering their demands during potential peak periods," NiMo said. However, NiMo recognized that customer acceptance of capacity tags would be a concern, since customers would not know their capacity tag until after the annual peak has been determined.

Another option would be to impose a demand charge based upon the capacity costs from the prior year and the customer's maximum demand. NiMo noted Consolidated Edison uses a monthly demand charge to collect capacity costs from retail customers, which creates an incentive for customers to reduce their own peak use every month, including the month in which the electric system peaks.

A third alternative would be to allocate the capacity costs to energy prices using probability of peak calculations for weekdays, excluding holidays, while a fourth option would be to fine tune the aforementioned third option by creating clusters of days with similar size peak loads and clustering the allocation of capacity costs to fewer days and hours through probability calculations.

NiMo reported 152 customers are currently on the MHP tariff. Another 526 customers are eligible for the MHP tariff but elect to be served by ESCOs.

In a customer survey, NiMo found that the most frequently mentioned barrier to load shifting was an inflexible labor schedule which prevents respondents from shifting load from their normally scheduled time to a lower cost period. About half of respondents mentioned a lack of resources to monitor prices as a barrier to price response.

While respondents did not report a significant amount of load-shifting actions, energy efficiency measures have been more popular, with 40% of respondents implementing energy efficiency measures and another 40% intending to undertake such measures in the next year.

"Thus, the hourly load information may be providing incentives to customers to conserve a greater amount of electricity, but hourly prices are not convincing customers to moderate usage away from hours with peak loads," NiMo concluded.

Load factors have improved among MHP customers. But NiMo said that while some load shifting is occurring, customers do not seem to be focusing their demand response to periods of highest peaks.

NiMo told the PSC it will be developing an expansion of time-of-use tariffs in the coming months, in conjunction with smart grid pilot programs. NiMo expects to recommend changes to the MHP tariff as part of this broader undertaking.

***EFH** ... from 1:*

results. Higher operating expenses associated with retail customer growth, as well as Luminant plant outages, also decreased results $80 million versus 2007. Lower baseload generation due to Sandow 4 and Big Brown unplanned outages had a negative $30 million impact on the 2008 results.

TXU reported it ended the year recording its eighteenth consecutive month of residential customer growth, pushing its residential customer count to 1.93 million, versus 1.88 million at year-end 2007. The rate of residential customer growth did slow in the fourth quarter, however. Average revenue per residential customer was $134.42/MWh for 2008, up from $127.87/MWh a year ago.

TXU also saw a modest gain in small business customers (under 1 MW), increasing customer count to 257,000 from 256,000 a year ago, while large C&I customer count continued to fall at 25,000 versus 33,000 a year ago.

Total customer count inched to 2.21 million from 2.16 million at year-end 2007. TXU has about 1.8 million customers in its traditional Dallas territory, or about 58% of the market. Estimated ERCOT market share for residential customers grew slightly at 37% versus 36% a year ago, while non-residential estimated market share dipped to 26% versus 27% a year ago.

EFH executives said during an earnings call that, thus far, reduced usage has been confined to large C&I customers, and it has yet to see any appreciable decreased usage among residential customers due to the economy.

TXU Energy CEO Jim Burke noted that while there has been small movement to lower pricing among a few REPs, TXU would remain disciplined with its margins.

EFH executives reported a significant slowdown in wind development in the near term as access to capital dries up, especially in the West Zone, though some new build will likely come online in the South. Executives expect construction to pick up beyond 2009, particularly as Competitive Renewable Energy Zone development accelerates.

On a consolidated basis, EFH posted a net loss of $9.8 billion compared to a net loss of $637 million for 2007, mostly on the aforementioned impairment charges related to goodwill, trade name and natural gas-fueled generation plants. Excluding such items, EFH recorded an adjusted consolidated loss $876 million for 2008, reversing net income of $1.3 billion in 2007.

Pepco *... from 1:*

While Pepco Holdings expects the retail energy supply business to remain profitable based on its existing contract backlog and the margins that have been locked in with corresponding wholesale energy purchase contracts, Pepco Energy Services has been hit with higher churn and slowed enrollments.

The retailer has increased its pricing to reflect the new higher cost of capital. Although several other retailers have reported taking similar actions, Pepco Energy Services reported it has been experiencing reduced retail customer retention levels and reduced levels of new retail customer acquisition, which it blamed on its new pricing. Pepco Energy Services started embedding the higher cost of capital in rates around October, and since then it has seen a decrease in its ability to win business as well as retain customers, Pepco Energy Services CEO John Huffman said. Huffman added that Pepco Energy Services hasn't seen competitors take similar pricing actions.