Energy Choice Matters

May 8, 2008

Ambridge Owner Buying Champion Energy Services

Champion Energy Services is to be bought by a new entity called Champion Energy Holdings which is owned indirectly by the owner of Ambridge Energy, James Crane, with Ambridge customers being transferred to Champion Energy Services, subject to PUCT approval of REP certificate amendments.

Champion Energy Services is currently owned by three members: Eagle Energy Partners I, Bay Street Energy, and Robert Doty, President of Champion Energy Services. Crane's new Champion Energy Holdings will purchase all of the ownership interests held by Eagle Energy Partners and Bay Street Energy. Doty will then contribute his Champion interests to Holdings.

Champion Energy Holdings will then contribute all Champion interests to Champion Energy Marketing LLC, a 100% owned subsidiary of Holdings. Crane will indirectly own about 97.5% of Holdings and Doty will own about 2.5%.

In a separate transaction, Champion Energy Marketing will then purchase Ambridge from Crane, who is the sole current member of Ambridge.

Ambridge's current customers and wholesale positions will be transferred to Champion Energy Services but Ambridge will retain its REP certificate, and intends to serve new customers in the future, it told the PUCT.

Ambridge, a Houston-based start-up which completed ERCOT testing less than a year ago, recently amended its REP certificate to add the trade name Guaranteed Electric, under which it markets prepaid service (Matters, 4/1/08).

Doty will continue as President of Champion Energy Services.

The various transactions are conditioned on PUCT approval of the REPs' certificate amendments and other closing conditions (PUCT dockets 35591, 35654).

First Choice Power Ending Speculative Trading After Rough First Quarter

PNM Resources first quarter earnings plunged from speculative losses at First Choice Power and EnergyCo as well as regulatory disallowances at its New Mexico utility.

PNM reported a loss of $48.6 million versus a profit of $29.7 million in the year-ago quarter.

First Choice and EnergyCo are leaving speculative trading altogether after a quarter in which First Choice was burned by forward, arbitraged power positions among delivery zones within ERCOT, betting that the difference in zonal prices would be reduced.

But extreme congestion created negative zonal power prices and surging costs to move power between zones, PNM reported, with delivery prices fluctuating between the historic average of $1.50/MWh up to $100/MWh.

First Choice incurred a non-recurring, after-tax loss of approximately $30.3 million during the first quarter, with $22 million of that total being unrealized.

Executives pointed out that there had been no indication of ERCOT transmission constraints, with only six congestion events in first two months of 2007. ERCOT experienced 74 congestion events in first two months of 2008, PNM reported.

ERCOT realized total market inter-zonal congestion costs for Q1 2008 that were 30 times those of Q1 2007, PNM said.

Executives blamed ERCOT's reliance on systems to correct congestion, rather than using human

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RESA Asks DPUC to Reconsider Long-Term Contracts

The Retail Energy Supply Association asked the Connecticut DPUC to clarify and reconsider its decision to allow distribution utilities to procure bilateral, long-term contracts for standard service (Matters, 4/4/08).

Departing from a draft decision (Matters, 3/18/08), the Department is allowing electric distribution companies (EDCs) to procure up to 20% of their standard service load via long-term (four or more years), bilateral contracts. An earlier draft would have prohibited PPAs over four years in length, while limiting shorter-term bilaterals to 20% of load.

The "significant changes" from the draft decision, including deletion of language regarding risks of long-term contracts and the state's policy supporting retail competition, seem to show an apparent policy construct at the Department favoring a return to more traditional regulation in lieu of polices that promote customer choice, RESA observed.

RESA urged the DPUC to clarify that it will hold public hearings on the PPAs before any long-term contracts are approved (07-06-58, 06-01-08RE01).

Risks from long-term contracts - stranded costs, ratepayer harm and damage to the competitive market - are increased if the DPUC limits review of the PPAs to the Department, Office of Consumer Counsel and OCC's consultant, RESA argued.

The DPUC's proviso that long-term contracts cannot make up more than 20% of an EDC's load hasn't been fully vetted or explained, RESA pointed out.

For example, RESA noted there is little in the record regarding how to count megawatts of load that will make up the 20%, especially in longer-term contracts. With customer migration, what once constituted 20% of EDC load could become 50% of remaining load in subsequent years, RESA observed.

Since long-term contracts will carry different risks and risk premiums from the current shorter-term contracts used for standard service, the review process should be distinct from the current procedure to approve standard service RFP results, RESA added.

A clear signal from the DPUC assuring the marketplace that it will allow public comment on the long-term contracts would help inform wholesale and retail suppliers that the Department's order is not a move towards re-regulation, RESA explained.

The DPUC's decision left open the question of how to use the power from any EDC long-term contracts, though it did state the Department was inclined to use the power for standard service.

RESA urged the Department to consider that question in an open forum with opportunity for public comment.

To the extent the decision's elimination of specific language recognizing the state's policy of retail competition demonstrates a shift in policy back towards regulation, the final decision contravenes the legislature's intent, which last year clearly backed retail competition in the state's electric industry, RESA argued.

Record Enrollments at EnerNOC

EnerNOC's gross margin is growing despite increased competition from a range of providers in the demand response space, it told analysts on a conference call.

Gross margin for the first quarter was 34.8% versus 29.1% a year ago. CEO Tim Healy attributed the success to product differentiation.

Still, EnerNOC lost $11 million for the quarter, versus a loss of $3.8 million in the prior year's quarter. Executives attributed the loss to investment in expanding EnerNOC's business, and projected full-year profitability by 2010.

EnerNOC had a record quarter of sales, enrolling 390 new megawatts under management. That pushed its total portfolio to 1,502 MW, and the firm expects 2 GW under contract by year end.

Healy sees a strong environment for demand response given the economic downturn that has executives concerned with the bottom line. That climate makes demand response investments, which produce a revenue stream, more favorable than large energy efficiency measures which fare better in better economic times because of their out-of-pocket expenses, Healy observed. Complex rules and measurement and verification procedures mean companies are likely to seek a third-party provider for demand response, he noted.

The overall regulatory climate for demand response is favorable, EnerNOC President David Brewster added, arguing that "speedbumps" in ISO New England and California show demand response is coming of age.

FERC's wholesale competition NOPR indicates the Commission is a strong advocate for demand response, which will open new markets to load resources, Brewster reasoned.

Brewster sees a bigger role for demand response in ERCOT as that market increasingly uses intermittent generation.

CMP Sees Higher Costs from Leaving ISO-NE

Maine's electricity consumers will be better off if Maine's utilities remain a part of ISO New England, Central Maine Power reported to the PUC in presenting an analysis by The NorthBridge Group (2008-156).

The case for separating Maine's utilities from ISO-NE rests upon two equally doubtful and unlikely assumptions: first, that there are substantial costs now borne by Maine's consumers as a result of Maine's participation in ISO-NE that could be avoided by leaving; and second, that the essential coordination, market and reliability functions now performed for Maine by ISO-NE could be replaced at a reasonably comparable cost.

Neither of those assumptions appears to be correct, CMP argued.

In fact, the costs and risks of Maine's withdrawal from ISO-NE appear to far outweigh the perceived benefits, CMP claimed.

Leaving the ISO would hinder Maine's goals for greater renewable generation, meeting Regional Greenhouse Gas Initiative targets, and stronger ties with New Brunswick, CMP added.

The alternatives to remaining in ISO-NE -- a stand-alone Maine grid or a Maine/New Brunswick RTO -- would cost Maine customers $1.0 to $2.3 billion more in capacity, energy and transmission costs on a net present value basis, NorthBridge calculated.

FERC rules prohibit Maine from imposing a "toll" on Maine generators for exporting power to ISO-NE if Maine does leave the RTO, NorthBridge noted. In other words, if Maine's utilities withdraw from ISO-NE, they cannot expect to "trap" generation within the State, NorthBridge explained.

Recent FERC decisions have made clear that utilities withdrawing from RTOs are not automatically excused from continuing to pay for investments that were made (and allocated among customers) during the period of their membership, NorthBridge added.

"In return for the benefits to others from a decision by Maine to remain in ISO-NE, including the value provided by incremental renewable and transmission resources, and in light of the payments that the State has already provided to the other, wealthier New England states under the current cost allocation structure for transmission investment, Maine should considering seeking compensation of some sort," NorthBridge suggested.

Compensation could result from cost socialization for Maine grid projects to access renewables, or capacity market reforms.

Delmarva Selects Winners in Wind RFP

Delmarva Power and 12 partner cooperatives have selected six winning bidders for providing land-based wind power under long-term contracts that's to save Delmarva's Delaware customers $80 million a year versus the embattled Bluewater Wind offshore proposal, Delmarva reported.

Delmarva would purchase 310 MW under the PPAs if the Delaware PSC approves the deal. SOS customers would receive 160 MW of that total, while 150 MW would be allocated to migrated customers. The utility intends to file an application in June. Another 150 MW would be bought by a dozen cooperatives.

The savings work out to $240 per year for the typical residential customer. Delmarva called the savings a true, all-in comparison to the Bluewater plan since the winning contracts include all related services, including transportation to Delaware.

Delmarva is still negotiating final contracts so did not disclose bidder identities or prices. The PPAs would last 15-20 years with the projects coming online in 2009-2010.

The projects, all of which are new, are primarily located in Maryland and Pennsylvania, except for 50 MW.

REPs Want Clarification on Recipient of Oncor Rebates

REPs suggested a few tweaks to Oncor's compliance filing regarding service quality rebates but otherwise supported the filing (Matters, 4/8/08).

REPs suggested a change to an Oncor-REP agreement dictating the rebate's structure to ensure REPs can practically execute the rebates (35546). The agreement calls for REPs to issue rebates to end-users occupying a premise on the day rebates are issued. But TXU Energy and the Alliance for Retail Markets pointed out that REPs have no practical means of remitting rebates to such a person.

TXU noted that REPs deal with their customer of record, who may be different than the premise's occupant, and suggested making reference to the REP's customer of record in the Oncor agreement.

ARM explained that the REP, at best, will only be able to pass through the rebate to the end-use customer that is associated with the ESI-ID identified by Oncor. Thus ARM requested that the Oncor agreement reflect that rebates will go to customers associated with a specific ESI-ID, rather than a specific premise.

TXU and Reliant Energy both asked for greater clarity and specificity in the agreement to reflect the Texas SET 810-02 transactions Oncor will use to flow the credits to REPs, with TXU requesting that Oncor provide the SAC04 codes it intends to use.

Price Discrimination a Major Topic at Capacity Market Conference

Load representatives and state regulators generally had kinder words for ISO New England's Forward Capacity Auction over PJM's Reliability Pricing Model in a FERC technical conference on the two capacity markets (AD08-4).

While PJM Senior Vice President for Markets Andy Ott stopped short of calling RPM a "success," he pointed to positive trends (such as demand response and reversed retirements) in the just one-year of RPM's operation. Ultimately, it's premature to judge the market, Ott reported, a view echoed by many generators.

In dismissing claims made by APPA and other load interests, PJM Market Monitor Joseph Bowring assured FERC that, contrary to allegations, there has been no physical withholding in RPM. Bowring suggested many of the criticisms of RPM do not reflect issues with the market's design, but critics' fundamental problem with markets.

Price discrimination dominated much of the discussion, with Daniel Allegretti, Constellation Energy's Vice President and Director of Wholesale Energy Policy, arguing that the Portland Cement Alternative Market Design proposal inherently allows consumers to price discriminate against old and new capacity.

Price discrimination fundamentally does not work in a market setting where both older and newer generation assets provide the same service any more than it would work in a workplace environment, Allegretti explained. No one would imagine a working environment where a person's salary never increased throughout their working life even if they performed the same job for the entire time and newer hires were continually paid more for their services, Allegretti observed.

Allegretti found that American Forest & Paper Association's (AF&PA) Financial Performance Obligation (FPO) proposal, "is not outside of the realm of reason and offers an alternative that, with some effort and compromise, could provide a workable solution" (Matters, 5/7/08).

But the key elements of the FPO can be replicated with current financial products without changing the status quo, Allegretti pointed out.

One of the bigger problems Allegretti sees with the FPO is that it creates incentives to opt-out of the capacity market in high price and high volatility areas and exacerbates the problem of meeting planning reserves. Generators have an incentive to opt-out of the FPO any time the efficiently priced call option for the energy and capacity of the unit exceeds the clearing price in the FPO market.

The FPO also moves revenue from the energy and ancillary services markets to the capacity market, thereby reducing the impact of real time price signals that support intermittent generation and induce demand response, Allegretti reported.

The AF&PA proposal also seems at odds with the benefits of retail competition, he cautioned.

The FPO "over-solves" a concern over the lack of hedging instruments for load by forcing all consumers to enter into a standard and fully hedged position, explained Allegretti.

"This reduces the number of products that can be offered to consumers in retail choice states and reduces overall consumer welfare," Allegretti added.

Customers in retail choice states can currently choose their level of risk tolerance from the market, which is clearly illustrated by the number of hedging products offered in the retail energy market, Allegretti said.

But Don Sipe, an attorney representing AF&PA, reminded FERC staff that the capacity market was already intended to be a hedge, and consumers aren't wild about having to purchase an additional hedge to get the promised benefits.

The proposed reforms to capacity markets reflect load's desire to pay average costs instead of marginal costs, because such pricing is more advantageous to them right now, argued Roy Shanker, a consultant representing PJM Power Providers Group. But when marginal costs were lower, customers weren't concerned about generation developers going bankrupt because marginal costs couldn't cover their expenses, Shanker reminded.

Shanker stressed that stakeholders should not view the current Base Residual Auction as some make-or-break point for RPM. Shanker insisted the Cost of New Entry figures used for the auction aren't reflective of real-world economics and thus doesn't expect that much new generation can be attracted via the current auction.

While RPM has retained existing generation that may have otherwise retired, New Jersey BPU Commissioner Frederick Butler is "deeply concerned" that retaining those units locks up sites that are best suited for new and more efficient power plants.

"Therefore, if RPM is having any significant effect in the most congested areas of PJM, it is to make us more reliant on plants that use scarce and expensive fuels inefficiently, contribute to higher prices in the energy market, and cannot be relied upon for the long term," Butler claimed in written remarks.

Butler believes that over 90% of the revenues from the first four RPM auctions were paid to existing plants that had shown no intent to retire.

While the BPU may be more patient in waiting for RPM to mature, other stakeholders are not, and are breathing down the BPU's and PJM's neck over high prices. It's hard to give an answer of where customers' money is going in the absence of new build generation, Butler explained.

Texas Comptroller Cautions Against Government Influence in Energy Market

Public policies that attempt to pick winners in the race for new energy technologies are an inefficient way to achieve policy goals, and run the risk not only of wasting taxpayer money, but also of directing private investment away from more promising uses, the Texas Comptroller of Public Accounts concluded in a comprehensive report on Texas's energy outlook.

While both fossil fuels and alternative energy sources have benefited from government polices or intervention, such assistance must be applied carefully, the Comptroller cautioned, since the unintended consequences of government polices which favor specific resources can end up picking winners in the industry

The Comptroller favors setting policy goals and establishing broad guidelines that will allow the market to meet those goals in the most efficient means possible, regardless of fuel source or technology.

Any policies that discourage the use of existing fuel sources that have been relied on for decades (e.g. fossil fuels) will likely entail costs to taxpayers and consumers, the Comptroller added.

While Texas had only about 1.7 MW of solar generation in 2006, solar power would likely increase, given the state's favorable climate, if net metering becomes widely available, the report suggested.

Briefly:

Added CREZ Hearing Set for June 11-12

A hearing on ERCOT's Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study and GE's Ancillary Services study is set for June 11-12 under the latest schedule issued by PUCT docket management (Matters, 4/17/08). Direct testimony is due May 23 with a Commission final decision slated for consideration at the July 17 open meeting (33672).

FERC Denies Cargill ISO-NE Complaint

FERC denied a complaint by Cargill Power Markets against ISO New England and several transmission owners regarding service on the HQ Interconnection, finding that the ISO properly followed Order 890 (EL08-29). Cargill argued that HQ Interconnection service requested Nov. 1, 2007, should have been treated on a first-come, first-served basis rather than under Order 890's simultaneous submission window since the ISO had not yet incorporated Order 890's language into its tariff. FERC rejected Cargill's argument since the Commission had ordered RTOs to make tariff changes and compliance filings instituting Order 890's simultaneous submission window effective October 11, 2007. Although the ISO did not submit its compliance filing until Jan. 17, 2008, it requested an effective date of Oct. 11, 2007, which FERC granted in an accompanying order yesterday. Thus, the simultaneous submission window was in effect when Cargill requested service and the filed rate doctrine was not breached, FERC concluded.

FERC Approves MISO Manual Redispatch Waiver

FERC granted the Midwest ISO limited waiver of tariff provisions regarding manual redispatch to allow the ISO to use manual redispatch make-whole payments during testing of the ancillary services market (ASM) to ensure market participants participating in testing are paid adequately (ER07-1372-005). Normally such manual redispatch and related payments are limited to specific circumstances when reliability is compromised, but FERC noted using manual redispatch during ASM testing will remove a potential barrier to market participants' testing involvement. FERC also ruled that demand response will be eligible to receive such make-whole payments on a comparable basis as generation.

PNM Loss ... from 1

intervention. The typical length of congestion periods grew from about four hours to 10-15 hours, worsening exposure, executives noted.

PNM isn't comfortable enough that ERCOT can mange congestion effectively and won't risk further capital on speculative positions.

First Choice reported net ongoing earnings of $2.2 million for the first quarter, compared with earnings of $7.1 million in the year-ago period. GAAP losses were $24.1 million compared with earnings of $5.9 million in the prior year's quarter.

Sales were down 4% due to milder weather but First Choice avoided the customer attrition that other REPs saw in the high-price environment. Customer count was flat.

PNM CEO Jeff Sterba pointed to the third quarter as the period in ERCOT with the most switching activity, since it's immediately after customers get their first summer power bill.

Average retail margin was about $21/MWh, in line with expectations, but down from $27/MWh in 2007.

PNM's equity in the net GAAP losses of EnergyCo was $15.2 million, compared with losses of $0.4 million in 2007. Net unrealized mark-to-market losses on economic hedges primarily drove the results.