Energy Choice Matters
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Unhedged ERCOT Position Could Have Doomed Commerce; Still Faces Stern Test

Commerce Energy is facing a largely unhedged position in ERCOT and does not have the capital to execute some of its growth strategies to become a integrated service provider, CEO Gregory Craig reported during an earnings call.

Accordingly, the extreme price run-ups in Texas are compressing Commerce's margins since the book is not yet hedged in the manner Craig would prefer, which would be fully hedged or nearly fully hedged.

Upon arriving at Commerce some four months ago, the book was almost fully unhedged, and Craig took what actions he could, given Commerce's limited capital and credit, to, "sort of dirty hedge the near-term fixed price piece of the book." That quick action has produced significant cost savings, Craig reported, prompting one analyst on the call to respond that he thought Commerce would not have made it through the summer if Craig had not arrived.

Despite the challenges in ERCOT, Commerce isn't stepping away from it, Craig said in answer to an analyst's question.

Craig sees ERCOT "filled with opportunity" as a high-growth market, although it's clearly a high volatility market right now.

Although ERCOT is the source for much of Commerce's bad debt, Craig committed to improving acquisition efforts to seek and acquire customers with lower levels of bad debt.

Despite the hedging, credit and bad debt challenges, Craig told investors the "fun stuff" is figuring out how to grow the company off a cool base. Craig cited acquiring hard assets, such as electric

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Bridgeport, GenConn, PSEG Favored by DPUC Draft on Ratebased Peakers

Bridgeport Energy II's (Dynegy-LS Power) Option 2, 360-MW Bridgeport plant, GenConn's (NRG Energy-United Illuminating) 188-MW Milford plant and PSEG's 133-MW New Haven plant are the peakers favored by the Connecticut DPUC in a draft decision awarding the right to build new ratebased, cost-of-service peaking generation (08-01-01, Matters, 4/9/08).

The resulting 681-MW portfolio (summer peaking capacity) will be able to provide approximately 321 MW of Ten Minute Non-Spinning Reserve (TMNSR).

Approving additional peakers would not be in ratepayers' interest, the draft concludes, because of the risk of paying for excess capacity not ultimately needed. Since peaking units have limited ability to participate in energy markets and deliver the types of benefits that baseload generating plants can deliver, risks from over-procuring peaking generation are higher, the DPUC noted.

Another risk is uncertainty regarding the need for peaking generation units in the future given: 1) the potential impact of new transmission; 2) potential eligibility of possibly lower cost demand-side resources to participate in the Locational Forward Reserve Market (LFRM) as substitutes for peaking generation; 3) the impact of future LFRM rule changes; 4) the impact of other capacity resources that Connecticut is currently implementing, including distributed generation, and 5) the long-term (30+ years) supply, demand and forward reserve conditions and their impact on market prices.

Bridgeport II Option 2 has the lowest Annual Fixed Revenue Requirement (AFRR) at $11.34/kW-month, the DPUC noted, and the Department had committed to procuring the first 290 MW, to

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PUCT Desires $2,250 Price (Not Bid) Cap

An emergency joint meeting of TAC and WMS is set for Friday after the PUCT expressed its intent that ERCOT should expeditiously make revisions so that the MCPE not rise above the current offer cap of $2,250/MWh.

Methodologies currently used to calculate the MCPE can use only one shadow price cap for all commercially significant constraints (CSCs) in ERCOT. When there is zonal congestion or there are two or more CSCs, the MCPE can significantly exceed existing offer caps. ERCOT is now to prevent that result from happening.

WMS and TAC's feedback will be provided at the ERCOT board's regularly scheduled June 17 meeting. Getting WMS and TAC to tackle the issue, which includes reviewing recommended changes from Independent Market Monitor Dan Jones as well as other stakeholders, was a key concern of Commissioner Paul Hudson at today's emergency Commission meeting, who felt that the more folks who touched the proposed changes, the better.

Commissioner Julie Parsley also urged caution since the energy only market was designed to support generators and encourage investment. ERCOT and the Commission need to make sure that any changes are the best thing for the market as a whole, including consumers, because strong markets benefit consumers. Prices have to be appropriate, not excessive, Parsley noted.

Jones' proposal would reduce the CSC shadow price cap from $5,600/MW to $5,000/MW and implement a $2,250/MWh cap on MCPE and an MCPE price floor of negative $1,000/MWh. If the MCPE is adjusted either due to the floor or cap (the adjustment could only be *ex post*), ERCOT would implement a CSC shadow price adjustment administratively for any binding CSCs. The most reasonable adjustment for the CSC shadow price is to divide the adjusted MCPE difference between the two most effective zones for each binding CSC by the shift factor difference for the same two zones, Jones suggested.

Dr. Shmuel Oren, a PUCT senior adviser, suggested a mechanism that avoids the need for caps on shadow prices since a cap becomes cumbersome and requires subsequent *ex post* price adjustments when more than one CSC is congested. The purpose of Oren's proposed procedure is to identify and exclude offers that will raise zonal prices above the offer cap (by virtue of their shift factors) from participating in price setting.

The two-step procedure would still allow hockey stick offers by "small fish" to set the system scarcity price when no congestion is present. But in the presence of zonal congestion only the high priced portion of the hockey stick is paid the high price (which reduces the incentive for hockey stick bidding in congested situations), Oren explained.

REPs Seek to Rescue Customers with Pending Switches During Mass Transitions

REPs, during a mass transition lessons learned workshop yesterday, asked for changes in the ERCOT mass transition process to permit REPs to execute previously scheduled switches for customers in a mass transition before the customers are dropped to POLRs.

Although the current mass transition process makes accommodations for scheduled switches inside of a certain window by keeping the customer off POLR and just switching the customer to the REP they had chosen before the mass transition , REPs say it needs some work.

The problem, REPs say, is that there's a window for keeping the customer from being dropped to a POLR so a scheduled switch can occur. If the scheduled switch is too far in the future relative to the mass transition, the customer will be dropped to the POLR, with the scheduled switch honored later, creating confusion for customers who could end up on three different REPs within some 45 days.

REPs suggested that ERCOT provide them with a list in non-EDI form (such as a spreadsheet) listing customers due to be dropped to POLR that a particular REP has scheduled for a later switch. That would notify the customer's intended new REP of the potential for the customer to be dropped to POLR before the switch occurs, and allow the REP to evaluate the business case for undertaking action to speed the switch to avoid the POLR drop.

REPs asked for clarity on what actions would be appropriate in such situations. While REPs tiptoed around the possibility of using an inappropriate Move-In transaction to expedite a switch before the POLR drop takes effect, they clearly would like some sort of priority or other mechanism so they would not have to resort to using Move-Ins.

The meeting focused on identifying areas of mass transition procedures needing change, rather than crafting new polices. The list of desired changes is to be next reviewed by Texas SET.

RESA Pushes for Quicker Disclosure of Conn. Default Rates

Connecticut EDCs should accelerate scheduled RFP dates for Standard Service by three weeks to give customers ample opportunity to compare publicly released Standard Service prices and competitive offers, the Retail Energy Supply Association told the DPUC (06-01-08RE02).

The "potential pitfalls" of the current approach have been further illuminated by the failure of Connecticut Light & Power and United Illuminating to make their recent Standard Service and Last Resort Service filings, respectively, by the dates they proposed in a working group report (Matters, 3/18/08).

"These delays have narrowed the already small window during which suppliers can enroll customers in June for a July 1 start date," RESA explained.

The Department has previously noted, in the disclosure label docket, that providing price information is the best way to compare offerings, RESA reminded. But the current system does not give customers an ample opportunity to compare rates, RESA argued. Delays in posting rates are more problematic given the time needed to complete switches, which may take 45 days, RESA added. Thus, rates which aren't posted 45 days before they take effect may force customers to take default service for up to two billing cycles in cases where the customer would have switched to a competitive supplier had the rates been posted earlier.

RESA explained that by making the RFP earlier by three weeks, EDCs could file rates with the DPUC 60 days before they take effect, with approval coming as soon as practicable. That would allow customers sufficient time to compare offers, RESA reported. Other than moving forward the initial RFP date, RESA would keep the suggested timeline from the working group. Dominion Retail has urged the DPUC to approve rates 60 days before they take effect (Matters, 4/23/08).

The working group contemplated Standard Service rates being filed 40 days before they take effect, with less than a month between DPUC approval and effective date.

While RESA noted its proposal would push standard service procurement three weeks further out from the effective date, RESA reasoned that such action would not compromise timely price signals in Standard Service rates because rates are already blended over three years. Making the RFP three weeks earlier would thus have little effect on the price signals reflected in Standard Service rates, since they are already stale by design.

Last Resort Service prices are another matter, however. RESA observed that the legislature, by instituting quarterly pricing, wants last resort rates to reflect current market pricing. To balance the goal of market reflective pricing with the need for customers to have time to compare rates, RESA suggested moving the quarterly last resort RFPs to 10 days earlier than the working group proposal. Such a schedule would have last resort rates filed with the Commission 40 days prior to their effective date.

UI Files Last Resort Rates

United Illuminating filed Last Resort Service rates for the July through September quarter with the DPUC (08-06-07):

July - Sept. 2008 UI LRS GSC Rates (¢/kWh)

Month	On-Peak	Off-Peak
July	15.7243	15.7243
August	15.8286	15.8286
September	14.0455	14.0455

CTCleanEnergyOptions Bidders, Prices Released

Current providers Sterling Planet and Community Energy were the winning bidders for the CTCleanEnergyOptions program, Connecticut Light & Power and United Illuminating reported (07-01-09). Customers will continue to have a 50% green option and 100% option, while large customers can also choose

10%, 20%, 30% or 40%. Prices per provider are as follows:

Sterling Planet	2008	2009	2010	2011
Price (¢/kWh)	1.15	1.35	1.35	1.5
Product Mix				
Class I New England	0%	0%	0%	0%
Class I New Regional	25%	30%	30%	35%
Class I National	50%	50%	50%	50%
Other RECs	25%	20%	20%	15%

Community Energy	2008	2009	2010	2011
Price (¢/kWh)	1.5	1.5	1.5	1.5
Product Mix				
Class I New England	0	0	0	0
Class I New Regional	33%	33%	33%	33%
Class I National	33%	33%	33%	33%
Other RECs	34%	34%	34%	34%

Briefly:

Capacity Market Advocates Tout RPM to Calif. PUC

California capacity market proponents moved to lodge several favorable reports regarding PJM's Reliability Pricing Model in the California PUC's resource adequacy rulemaking (R. 05-12-013), countering a previous motion to lodge from supporters of a bilateral market who wanted to include RPM Buyers' March motion for a FERC technical conference on RPM. California Forward Capacity Market Advocates (CFCMA), Constellation, Dynegy, and Mirant argued that including a PJM Power Providers/CRA International RPM report, as well as recent RPM auction results and related news releases, in the record would, "serve to provide appropriate balance to the rather one-sided documents proffered by the [Bilateral Trading Group]."

Ex-NCG Manager Launches New Broker in Md.

EGP Energy Solutions, doing business as Atlantic Energy Resources, applied for a broker license at the Maryland PSC, with a former manager of troubled NCG Energy Solutions (Matters, 5/20/08) as co-owner, president and senior energy analyst. Baltimore-based Atlantic Energy Resources would broker C&I load in each of the four IOU territories. President Patrick Hall, "helped to start the Maryland office of NCG Energy Solutions," Atlantic Energy Resources' application states. Hall later became Mid-Atlantic regional manager, overseeing brokering in Maryland, Delaware, and D.C. EGP Energy Solutions CEO Kenneth Abner lists management level sales and consulting experience in energy brokerage, technology and education, and owns the other 50% share of the broker.

Prehearing Date Set for Illinois ABC Complaint

An Illinois ALJ set a prehearing conference for June 26 regarding BlueStar Energy's complaint against three brokers under the new ABC Law (Matters, 6/5/08, docket 08-0364).

Duke Energy Ohio Submits Latest GCR

Duke Energy Ohio submitted to PUCO its gas cost recovery rate (GCRR) of $1.1873 per 100 cubic feet to be charged during the revenue month of July (08-218-GA-GCR).

PUCT Staff Would Reject Always Electric REP Application

The PUCT staff recommended denying a REP certificate for Always Electric because Always Electric has not met financial qualifications (Matters, 5/13/08, 35663). While Always provided the PUCT with contact information to verify a bank account balance, that does not satisfy evidentiary standards needed for approval, as the resources available to the REP must be authenticated by independent, third party documentation. Further, the account is held by a member of the company, and a REP can only rely on a principal of the applicant if the REP provides a guaranty agreement, which Always has not done, staff noted.

PNM-Cap Rock Deal Would Not Impede Competition, Staff Testifies

PNM Resources' acquisition of Cap Rock Energy will not impede competition, Shawnee Claiborn-Pinto, senior retail market analyst at the PUCT, testified (35460, Matters, 3/18/08). The Commission's authority to transition the Cap Rock areas (in both ERCOT and SPP) to retail competition is not affected by the merger. Retail competition can be introduced at a later time, and the issue should be addressed on its own merits and not addressed in the merger docket. Claiborn-Pinto also testified that the merger will not affect the Commission's oversight of the merged company, and will not result in market power.

Occidental Power Services Approved as Option 2 REP

The PUCT granted Occidental Power Services an Option 2 REP Certificate, allowing Occidental Power Services to sell retail power only to previously identified specific customers over 1 MW in size. In this case, it will supply Occidental Chemical Corporation.

Occidental Power Marketing Rebuts Service Area Complaint from Co-op

REP Occidental Power Marketing's provision of retail electric service to an affiliate's oil fields in Kent County, Texas, is not violating Big Country Electric Cooperative's exclusive right to provide service in its certified area, Occidental told the PUCT (Matters, 5/20/08, 35690). The fields' internal distribution system, connected to Oncor and thus open to choice, predate the effective date of PURA and thus such service is grandfathered, Occidental noted. In fact, Big Country Electric's predecessor conceded in its CCN application the right of existing distribution systems to serve customers.

Milford Power, Blumenthal Reach Pact

Milford Power and Connecticut Attorney General Richard Blumenthal reached a settlement over Milford's Reliability Must Run contract. According to the AG, ratepayers will be refunded $4 million in the form of lower bills and save an additional $34 million between September 30 and June 1, 2010.

DRA Raises Specter of Current ERCOT Turmoil in Return of Direct Access

It didn't take long for a stakeholder to start using scare tactics regarding the current market environment in ERCOT. In post-workshop comments on the California PUC's investigation into lifting the suspension of direct access (Matters, 6/11/08), the Division of Ratepayer Advocates raised concerns about the viability of competitive suppliers and the potential for large swings in IOU load capacity needs, should mass transitions be prompted by increased volatility. The Market Redesign and Technology Upgrade, "is expected to, and in fact designed, to result in more volatile energy markets than California has seen since the energy crisis," DRA suggested (R. 07-05-025).

We'll print DRA's comments related to ERCOT, minus footnotes, and let ERCOT market participants judge if it's an accurate description of the market design:

"Recent events in the Texas energy markets highlight an inherent frailty of Energy Service Providers (ESPs). Texas has designed its long-term energy supply markets to foster the development of ESPs and non-IOU investment in generation assets. As the volatility of energy prices in ERCOT (Texas' regional transmission reliability organization) increased for a brief period recently, ESPs, some of which rely chiefly on the spot markets, were unable to recover sufficient income through tariffed rates to pay for their short-term energy supply obligations. As a result, several ESPs ceased operation and filed for bankruptcy in recent weeks. Their several thousand customers have been transferred to Providers of Last Resort ("POLRs") and now face significantly higher rates.

"These events in Texas gives rise to questions about whether and how POLRs should prepare in their long-term capacity planning for the return of significant numbers direct access customers due to energy price volatility. The IOUs' obligation to serve returning customers may require duplicative procurement, if both an ESP and an IOU contract for capacity those customers [sic]. The added costs must be evaluated.

"Texas' energy market is designed to provide generators with a greater percent of their fixed expenses through energy rather than capacity payments than currently is the case in California and previously arose in Texas' IOU-centered procurement paradigm. CAISO expects to implement a redesigned energy market paradigm, called MRTU, in the fall of 2008. MRTU is expected to, and in fact designed, to result in more volatile energy markets than California has seen since the energy crisis. It is intended that bid caps will rise to $1000 per kWh, and beyond.

"Currently, DA retailers serve less than ten percent of California's end users. The reopening of DA, however, could result in a significant increase in the number of customers served by ESPs rather than IOUs. This rise, combined with the implementation of MRTU threatens to expose California to the risk of emergency reversion of a significant percent of customers back to POLRs if MRTU's anticipated volatile energy prices also cause ESP bankruptcies.

"DRA suggests that it is unwise to consider the reopening of DA until after California's market participants have had a year of experience with MRTU's expected energy price volatility. Without such market experience, the Commission and energy providers will have no basis to calculate the actual volatility of MRTU energy prices, or how many customers may be transferred to POLR service due to ESP financial failures resulting from such energy price volatility."

Additionally, in a footnote, DRA explains the ERCOT market as such:

"An important note is that Texas has specifically designed its energy market to feature substantially higher IOU energy prices than those available through ESPs. This market design element was intended to incent customers to patronize ESPs rather than IOUs."

Commerce ... *from 1*

power generation or gas storage, that would help complement Commerce's natural long position, as potentially enhancing margins and helping reduce risk by providing some natural hedging.

Buying or controlling hard assets would make Commerce more of an integrated energy services company, as opposed to a single revenue source retail aggregator, Craig explained. That would diversify income thus lowering risks.

Commerce also has its eyes on chances to scoop up the books of failing competitors, particularly in ERCOT, but unfortunately, Commerce is not financially healthy enough to aggressively attack such acquisitions. Still, it's not out of the question that Commerce could acquire smaller customer books and integrate them as a method of growth, Craig added.

But Craig has to right the ship before any such plans are possible.

High operating costs and bad debt expense in the quarter led to a net loss of $9.5 million versus net income of $1.5 million a year ago. Results were also impacted by the write-down of intangible assets related to selling its Skipping Stone energy consulting business (Matters, 6/4/08).

Customer count fell to 165,000 as of April 30, 2008, down from 175,000 three months ago, and down from 185,000 a year ago. Quarterly electric sales reached 510,000 MWh versus 485,000 a year ago while gas sales fell to 4,007,000 DTH from 4,612,000 in the year-ago quarter.

Quarterly net revenues inched to $105 million from $101 million, primarily reflecting higher retail electricity sales to customers in Texas and Pennsylvania. Retail electricity revenue was up 21% to $63.9 million from $52.7 million in the last year's quarter. Retail natural gas revenue was down slightly to $41.6 million from $42.9 million in the third quarter of the prior year.

Gross profit was $14.1 million versus $17.6 million a year ago. Gross profit from retail electricity sales marginally decreased to $8.9 million from $9 million in the third quarter of last year. Gross margin from retail natural gas sales increased 47% to $5.2 million, compared with $3.5 million in the same quarter a year ago, from primarily higher margins in California and Ohio.

Selling and marketing expenses rose to $3.3 million from $2.6 million in the prior year's quarter. The increase reflected higher third-party sales expenses related to expanded customer acquisition initiatives. General and administrative expenses increased to $18.7 million from $9.8 million for the third quarter of last year. The 2008 quarter includes bad debt expense of $7.9 million -- $7.3 million higher than the third quarter of 2007.

As detailed last quarter (Matters, 3/14/08), Commerce is suffering from higher bad debt as the retailer added customers but did not upgrade its backoffice systems rapidly enough to make collection calls to customers within a short period of their balance becoming delinquent.

Commerce has become more conservative when it comes to recording bad debt expense and now fully reserves most accounts receivable that are 90 days or more old. Over 90 day balances increased $6.3 million in the third quarter of fiscal 2008. Commerce also has refined its processes for estimating bad debt expense to include a higher percentage of accounts receivable aged under 90 days. Its also requires deposits from customers with low credit scores and is strengthening electronic data interfaces to efficiently process larger transaction volumes.

Commerce anticipates that bad debt expense in the fourth quarter of 2008 will again be higher than its average expense. The retailer still expects further reduction in bad debt expense during fiscal 2009, trending toward historical levels.

Craig would be "surprised" to see direct access still suspended in California two years from now.

Craig reported Commerce has over 20,000 California customers, and is one of only a handful of retailers licensed to supply both gas and electricity there. The existing customer base and licenses for both fuels are a real competitive advantage, Craig noted.

Commerce is to use the next several months to terminate its relationship with Wachovia and seek additional, increased, and perhaps a more appropriate financing arrangement with a global commodity bank.

Conn. Peakers ... *from 1*

cover Connecticut's LFRM shortfall, based on a $/kilowatt-month basis.

The draft also favors Bridgeport II's Option 2 due to its: 1) commercial operation date of September 30, 2010; 2) Southwest Connecticut location; 3) local support for the project; 4) low project execution risk due to ownership diversity; 5) low project execution risk due to an advanced stage of project development; 6) relatively low risk of substantial capital cost increases; 7) fuel diversity from dual fuel and fuel switching capability; and 8) use of an existing site.

However, Bridgeport II Option 2 does not include TMNSR units, which prompted the DPUC to favor a larger portfolio than recommended by prosecutorial staff, because the Department desires 300 MW of TMNSR.

That's why the draft would select the GenConn 4 and PSEG peakers. An "overhang block" of additional capacity would further depress prices while not exposing customers to over-procurement.

In selecting the extra capacity, the draft excludes units that cannot run on dual fuels, since performing on one fuel type is not a reasonable risk for ratepayers, especially given the 30-40 year contracts the peakers will receive. The Department, "is unwilling to make a 40 year bet on the price differential between oil and natural gas, or on the availability of either resource," the draft would find. The dual fuel requirement eliminated Connecticut Light & Power's Lebanon plant and GenConn's Montville proposal.

The draft favors splitting the extra capacity between two suppliers, rather than accepting additional megawatts from other GenConn proposals, because project execution risk is decreased by selecting a portfolio of projects reflecting the greatest amount of ownership diversity possible. Further, it is in the best interest of ratepayers, from both reliability and economic standpoint, to spread the risk among three peaking generation projects developed by three owners versus three projects developed by two owners, the draft concludes.

Lower costs relative to other projects, Southwest Connecticut location, local support, and use of existing sites were among the reasons the draft cited for favoring the GenConn 4 and PSEG proposals over competing projects.

PSEG’s plant is in the better interest of ratepayers than GenConn's Middletown plant because of PSEG's better location on the transmission system nearer the Southwest Connecticut load. Furthermore, the draft noted that including GenConn Middletown in the three projects selected would present greater risk because of the procurement size.

The draft would require the chosen peakers to bid into and clear in the forward capacity market no later than the first period for which they are eligible. If there is any locational separation in the forward capacity markets the projects must bid as Connecticut resources, unless otherwise ordered by the Department. The projects should be bid in a manner in which they do not set the clearing price, and for a term of only one year, the draft directs. In all subsequent periods the units must bid in as price takers and cannot delist unless directed to do so by the DPUC.