Energy Choice Matters

*January 19, 2010*

# Luminant Proposes NPRR to Ease Nodal Collateral Requirements

Luminant has submitted proposed language for a Nodal Protocol Revision Request (NPRR) to revise the nodal collateral requirements by Qualified Scheduling Entities (QSEs) who participate in the Day-Ahead Market (DAM), which Luminant said will potentially reduce the collateral burden for QSE bids while sufficiently collateralizing ERCOT.

The revisions are based on discussions held at the Market Credit Working Group, Luminant said.

Luminant called the current collateral requirements for QSEs to participate in the Day-Ahead Market "significant," noting that they are based on potential offers and bids and not what is actually cleared through the market. "Thus, Market Participants have an increased cost of credit," Luminant said.

Luminant noted that there is concern among some market participants that the "significant collateral requirements" on QSEs will discourage market participants from participating in the Day-Ahead Market, which will create inefficiencies and additional energy price volatility. "Additionally, unhedged QSE Load in the DAM may result in extreme default risk in Real-Time," Luminant said.

The changes proposed by Luminant in the NPRR address the over-collateralization of QSEs, "and better reflect the risk and costs of DAM participation," Luminant said.

Currently, under the nodal protocols, credit exposure for each Day-Ahead Market Energy Bid is equal to the quantity of the bid multiplied by the bid price. Under Luminant's proposal, the credit exposure would be calculated as the (i) quantity of the bid multiplied by (ii) a bid exposure price input that would be calculated as follows:

(i) If the DAM Energy Bid price is less than or equal to zero, then the bid exposure price input will equal zero.

(ii) For each MW portion of the DAM Energy bid, for the total quantity less than the "c"th percentile

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# Cerritos Says Any Load Limit on Aggregation Should be Based on Energy, Not Capacity

Any load limit to be placed on the opt-in, direct access aggregation service offered by the City of Cerritos, California as a community aggregator should be based on energy, not capacity, Cerritos said in comments on a California PUC proposed decision (A. 09-06-008).

As only reported in *Matters*, the draft order would limit the aggregated load to be served by Cerritos to its capacity interest in the Magnolia Power Project, under the terms of AB 80 (Only in Matters, 12/22/09). The draft would allow for an incremental increase in the load limit to reflect that Cerritos must procure supplies in addition to the output of the gas-fired Magnolia plant in order to meet RPS requirements.

While opposing any load limit on its aggregation, Cerritos argued that a capacity limit is unsupported by AB 80 and is contrary to the legislation's goals of allowing Cerritos to make use of its interest in the Magnolia plant to serve customers. An energy-based limit, while not ideal, would allow Cerritos to make greater use of the plant's output, the city said.

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## New York Market Revenues Remain Well Below Requirement for New GT Unit

Revenues from the New York ISO markets, "remain well below" what is necessary to attract new entry of a hypothetical benchmark gas-fueled, simple-cycle, combustion turbine (GT) in all three capacity zones, NYISO said in an annual report to FERC on the ICAP market (ER03-647).

The revenue margin, or benchmark revenue (energy, capacity and ancillaries) over required revenue for the hypothetical unit, are below.

**NYISO Revenue Margins**

| | **2005** | **2006** | **2007** | **2008** | **2009** |
|---|---|---|---|---|---|
| **NYCA** | 29% | 52% | 58% | 55% | 50% |
| **NYC** | 84% | 80% | 75% | 53% | 45% |
| **LI** | 92% | 101% | 73% | 55% | 49% |

The significant drop in ICAP Spot Market prices (attributed to revised mitigation rules) explains acceleration in the decline in revenue margins for New York City and Long Island, NYISO said.

NYISO said that its analysis of the market did not raise concerns about withholding in the NYCA, New York City, or Long Island markets.

In the New York City market, there was no unsold capacity in Summer 2009, and very little unoffered capacity. In May 2009, a Responsible Interface Party (i.e., the Installed Capacity Supplier for Special Case Resources) did not offer 6.3 MW, and in August 2009 a Responsible Interface Party did not offer 20 MW. Apart from these two situations, in the Summer 2009 Capability Period, the Installed Capacity Suppliers that did not offer capacity each had less than approximately 4 MW per Installed Capacity Supplier, NYISO said.

The Rest of State region had insignificant amounts of unoffered capacity relative to available capacity, as evidenced by offers in excess of close to 99% of the available capacity, NYISO added. The NYISO calculated the maximum price impact of the unoffered capacity, averaged over the six months of the Winter 2008/2009 and Summer 2009 Capability Periods as $0.60/kW-month and $0.28/kW-month, respectively. The relatively high seasonal average price impact of $0.60/kW-month was primarily due to a generation owner that inadvertently omitted offering approximately 678 MW in the January 2009 Spot Market Auction, which represents nearly three percent of the total available MW in the Rest of State region, NYISO said.

## WPTF Opposes Lower Scarcity Price for Sub-regional Shortfalls in CAISO

The Western Power Trading Forum objected to the California ISO's scarcity pricing proposal to comply with Order 719 on two counts, namely: WPTF objects to (1) the CAISO's proposal to set scarcity prices for sub-regional shortfalls for some services equal to a fraction of the price of a shortfall in the system region, and; (2) the CAISO's proposal to review the performance of the scarcity pricing proposal every three years (ER10-500).

The main tenets of CAISO's scarcity pricing proposal include:

- Scarcity pricing applies to the four reserve products the CAISO procures through its markets: spinning reserve, non-spinning reserve, regulation up and regulation down;
- The CAISO may determine scarcity prices for its system region (the CAISO Balancing Authority Area), its expanded system region (the CAISO Balancing Authority Area plus the intertie scheduling points with adjacent Balancing Authority Areas), or any of eight sub-regions within the system region; and
- The scarcity price for any ancillary service is set by a demand curve and will increase as the level of the shortage for that service increases.

However, WPTF noted that, in some cases, the CAISO has proposed to set the scarcity price for an ancillary services shortfall in an ancillary services sub-region at half of the scarcity price for an ancillary services shortfall in the expanded system region. More specifically, CAISO proposed that the sub-regional scarcity price for regulation up should be ten (10) percent of the effective bid cap, while the expanded system region scarcity price for regulation up should be twenty (20) percent of the effective bid cap.

CAISO said that this design reflects the relative value of these scarce resources, stating that when supplies in these sub-regions are insufficient to meet the requirements, there is no violation of NERC and WECC reliability standards, and that there is less of a threat to system reliability as compared to a scarcity condition in the expanded system region.

WPTF countered the interpretation that a failure to meet sub-regional reserve requirements is not a violation of either NERC or WECC reliability standards, citing NERC standard TOP-002-2, Requirement 7, which requires each Balancing Authority to meet its reserve requirements, including a requirement that the reserves be deliverable.

"The failure to maintain sufficient reserves in a local area is no less of a threat to reliability than a failure to maintain sufficient reserves in the CAISO Balancing Authority area, as demonstrated by the events of August 25, 2005 - the only day in which the CAISO shed firm load in the last five years. On that day, the CAISO maintained sufficient reserves on a Balancing Area-wide basis, but did not have sufficient 'deliverable' operating reserve South of Path 26," WPTF said.

However, Pacific Gas & Electric agreed with CAISO, arguing that, "the geographical cascading of the CAISO's proposal appropriately recognizes that a scarcity condition in a sub-region is a less serious threat to reliability as compared to a scarcity condition in the expanded CAISO balancing area."

J.P. Morgan Ventures Energy Corporation contended that, consistent with the larger market design, "it is imperative that the CAISO establish locational price signals to guide short-term operating and long-term investment decisions that will address locational needs."

"One of those needs is appropriate dispersion of operating reserves. Establishing a lower scarcity premium for reserve shortages in sub-regions sends the wrong signal to resource operators and investors. J.P. Morgan cautions the CAISO and the Commission against establishing lower sub-regional scarcity premiums while continuing to permit the CAISO to rely on non-market and opaque measures such as exceptional dispatch to address sub-regional capacity requirements," J.P. Morgan said.

Regarding the periodic review of scarcity pricing, WPTF urged an annual review, rather than the three-year review proposed by CAISO.

The California PUC said that, at the direction of FERC, the CAISO tariff proposes to allocate costs for regional Ancillary Services procured through the proposed Scarcity Pricing mechanism to the entire CAISO system rather than only to the deficient sub-region. "System-wide cost allocation for sub-regional deficiencies runs contrary to the basic principle of cost causation and creates an incentive for Load serving Entities to under-procure Ancillary Services to meet sub-regional needs," the PUC cautioned. "[T]he sub-regional cost allocation mechanism, as currently proposed, creates incentives for Load Serving Entities to rely on CAISO procurement of Ancillary Services rather than procuring such services themselves, as regional load will be able to spread costs for such Ancillary Services procured through the Scarcity Pricing mechanism to the entire system," the PUC added.

"If a sub-region within the CAISO footprint has insufficient Ancillary Services, then the costs of such shortage should be borne by the Load Serving Entity or Entities within that sub-region," the PUC said.

## NYISO Submits Tariff Changes to Avoid ICAP Price Anomaly from Different Capability Year Start

The New York ISO submitted proposed tariff changes at FERC to establish a Capability Year Adjustment Election which holders of Unforced Deliverability Rights (UDRs) may exercise under certain conditions, as NYISO said that the changes are needed to address a "quirk" in existing arrangements that could cause a temporary, and unwarranted, increase in capacity demand curve prices on Long Island during May 2010.

Under current rules, UDR rightsholders must inform NYISO no later than August 1 whether they intend to use the rights to treat External Unforced Capacity (UCAP) as "intra-Locality" UCAP in the next Capability Year, which begins May 1. Alternatively, UDR rightsholders may opt to return all or a portion of their UDRs to the

NYCA to be counted as emergency support capability in the NYISO's Locational Minimum ICAP Requirement studies, which would tend to result in a lower Locational Minimum ICAP Requirement.

NYISO said that an issue has arisen due to the UDRs held by LIPA associated with the Neptune cable linking Long Island and PJM. LIPA intends to use the UDRs to treat a PJM capacity contract as UCAP electrically located on Long Island during the 2010 Capability Year. In the past, LIPA has not used its Neptune UDRs for capacity and the Locational Minimum ICAP Requirement for Long Island reflects Neptune's traditional state as a source of emergency support capability (i.e., the ICAP requirement is lower than it would be if the UDRs were associated with locational capacity).

LIPA's choice to use the UDRs as capacity would result in the Locational Minimum ICAP requirement for Long Island increasing at the beginning of the next NYISO Capability Year (May 1, 2010). However, LIPA has noted that the capacity contract associated with the Neptune cable cannot be de-listed from PJM's forward capacity market (and therefore cannot be used as Long Island UCAP) until June 1, 2010.

"The likely consequence of the discrepancy between the start dates for the NYISO and PJM capacity years would be an increase in the Long Island ICAP requirement on May 1 without an accompanying increase in the supply of local UCAP until June 1," NYISO said. "It can reasonably be anticipated that this mismatch would cause a material increase in Long Island capacity demand curve prices during May. Such an increase would be unwarranted because Neptune would still, in fact, be available to provide emergency support capability during May 2010. This increase would therefore be an 'artificial' byproduct of a timing difference between NYISO and PJM capacity market rules," NYISO said.

Arguing that this situation should be avoided, NYISO said that the most readily implementable solution is to give holders of UDR rights from an External Control Area with a capability year start date that differs from the NYISO's start date an opportunity to have NYISO exclude those UDRs from the relevant Locational Minimum ICAP Requirement calculation for the first month of a given NYISO Capability Year. The proposed Capability Year Adjustment Election would also be available to other entities that hold rights to External UDRs, NYISO said, noting both PJM and ISO New England have capability years which begin on June 1.

A entity's right to make the election would be contingent on the demonstration of its commitment to utilize the UDRs in question to import capacity into a Locality, NYISO said. The Capability Year Adjustment Election would also be a one-time option for each block of UDRs held by a rightsholder. Once an election is made with respect to a given block of UDRs, any subsequent holder of the rights would not be entitled to a new election, NYISO said.

NYISO also said that it has committed to bring to stakeholders in 2010 a proposal to address possible actions for long-term alignment of capability years.

## *Briefly:*

**Clearview Applies for Pa. Electric License**

Clearview Electric has applied for a Pennsylvania electric supplier license as a broker/marketer, aggregator, and load serving entity, serving all customer classes in all service areas. Clearview said that it is serving approximately 10,000 meters in Texas, New York and Connecticut.

**Levco Announces New Conn. Rates**

Levco Energy, which markets for Dominion Retail in Connecticut, announced new fixed rates through December 31, 2010 for residential and small commercial customers of 10.3 cents per kilowatt-hour at Connecticut Light & Power and 10.5 cents per kilowatt-hour at United Illuminated.

**Peak Load Management Alliance, Utilimetrics Form Partnership**

The Peak Load Management Alliance (PLMA) and Utilimetrics, the smart utility association, announced yesterday that they have formed a partnership to facilitate communications and information sharing. The groups said that they will be coordinating collaborative efforts with educational, marketing and informational initiatives that promote power-grid reliability, improved operations, and effective resource utilization.

**Publication Note:**
Energy Choice Matters published an issue on January 18. Stories included:
- BGE Files Electric POR Discount Rates, Reduces Risk Factor, Defers Operational Component
- George Sets Hearing on Pa. Agency to Procure SOS Supplies, Enter Long-Term Contracts
- Md. OPC Recommends Separate, Concurrent Reviews of SOS, Ratebased Generation
- Texas Judge Remands CREZ Order to PUCT
- Gateway Energy Services Announces PPL Residential Pricing
- And more

## *Nodal Credit ... from 1*

of the Day-Ahead Settlement Point Price over the previous 30 days, the bid exposure price input will be zero.

(iii) For each MW portion of the DAM Energy bid, for the total quantity greater than or equal to the "c"th percentile of the Day-Ahead Settlement Point Price over the previous 30 days, the bid exposure price input will equal the greater of:

(A) Zero; or

(B) The lesser of:

(1) The "d"th percentile of the Day-Ahead Settlement Point Price over the previous 30 days; and

(2) The bid price.

*Where "c" and "d" are placeholders for percentiles to be determined by the Wholesale Market Subcommittee.*

Under Luminant's proposal, for each MW portion of a Day-Ahead Market Energy Only Offer:

(i) That has an offer price that is less than or equal to the "a"th percentile of the Day-Ahead Settlement Point Price over the previous 30 days, credit exposure will be reduced (when Settlement Point Price is positive) or increased (when the Settlement Point Price is negative) by the (i) quantity of the offer multiplied by (ii) the "b"th percentile of the Day-Ahead Settlement Point Price over the previous 30 days.

(ii) That has an offer price that is greater than the "a"th percentile of the Day-Ahead Settlement Point Price over the previous 30 days, the credit exposure reduction will be zero.

Luminant said that, under the revisions, market participants will have more options for hedging and reducing risk, thus delivering more options to customers.

Based on discussions with ERCOT Staff, Luminant understands that in order to complete a system change to implement its proposed NPRR by the December 2010 Texas Nodal Market Implementation Date, the NPRR will require approval within the next six to eight weeks. "Therefore, in light of the short time frame to implement such a system change, Luminant respectfully requests that this NPRR be identified as necessary prior to the Texas Nodal Market Implementation Date."

## *Cerritos ... from 1*

Cerritos noted that, under a load limit based on capacity, during most hours of the year it would have unused energy from the plant that it would be prohibited from selling at retail, contrary to AB 80. That's because due to load profiles, its cap would be set based on the peak demand of its direct access customers. However, at non-peak times, Cerritos would still have the same entitlement to energy from the Magnolia plant; however, the entitlement will exceed customers' demand, leaving Cerritos with unused power. Cerritos, however, could not sell such excess power to other retail customers, because if it did it would exceed its capacity-based load cap at the peak hour.

In contrast, if the load cap were set based on Cerritos' energy entitlement from the plant, Cerritos said that it would not face the problem of having unused power. Though not explicit, given this argument, Cerritos' proposal would allow it to serve load greater than its share in the Magnolia plant, for, in order to use all of its power during off-peak times, it would have to enroll more customers whom it could not serve directly from the Magnolia plant at peak times, and thus would procure supplies from other sources to serve such customers.

In its simplest form, Cerritos suggested an energy-based limit determined on an annual basis as Cerritos' 4.2% entitlement share in the Magnolia plant times output from the plant.