Control Number: 40000

Item Number: 582

Addendum StartPage: 0

PUC PROJECT NO. 40000

2013 DEC 16 PM 3: 13

COMMISSION PROCEEDING TO	**§**	**PUBLIC UTILITY COMMISSION**
ENSURE RESOURCE ADEQUACY IN	**§**	
TEXAS	**§**	**OF TEXAS**

FILING CLERK

TEXAS ENERGY ASSOCIATION FOR MARKETERS' COMMENTS ON COMMISSIONER RESOURCE ADEQUACY QUESTIONS

Texas Energy Association for Marketers (TEAM)[1] files these comments on the resource adequacy questions identified by Chairman Nelson and Commission Anderson in filings made on October 25 and November 15, 2013 respectively. TEAM has participated in all of the recent resource adequacy projects at the Commission and appreciates the opportunity to continue offering input to the work that the Commission, ERCOT, and market stakeholders have done to address potential challenges in the market's near future.

I. Introduction

TEAM consistently supports competitive market-based solutions to market design issues and advocates that any significant changes to the Texas electric market retain the fundamental structures that have made it the most successful competitive electricity market in the country. Specifically, as set out in the creation of this competitive retail market in Texas, retail electric providers must be independent companies that may not own generation or transmission and distribution utility facilities. Customer choice would be reduced significantly if the market were designed in such a way as to make it a practical and economic necessity for retail electric providers to be affiliated with generation.

TEAM recognizes that maintaining an adequate and reliable supply of electricity generation in ERCOT is critical to maintaining long-term confidence and liquidity in the competitive market. These comments address the specific questions raised by the Commission to be answered regarding the implementation of alternate market design changes that could be

[1] The members of TEAM participating in these comments are: Accent Energy d/b/a IGS Energy; Cirro Energy; DPI Energy (d/b/a Trusmart); Entrust Energy; Just Energy; Spark Energy; StarTex Power, Stream Energy; and TriEagle Energy.

582

employed to meet a reserve margin target or mandate. The scope of the questions posed is necessarily broad to seek input on multiple aspects of the electricity market as it relates to reliable and sufficient system operability. TEAM is best positioned to provide information on selected topics that relate to the potential retail market impacts of the potential market design changes that are being discussed for the wholesale generation market. Any design change to the wholesale market is going to incur costs that must ultimately be paid by consumers and it is imperative that the structure of these charges be analyzed and measured against whatever design change benefits are likely to be realized over a reasonable timeframe.

II. Response to Questions

Chairman Nelson Questions

Question 1. What resources should be allowed to participate in the market?

All resources should be allowed to participate in the market including entities representing load response as well as generation. REPs in the competitive ERCOT market, including members of TEAM, have been innovative in providing time of use and other price sensitive products to residential and small commercial customers to facilitate their control of electricity use in a manner that has direct and positive benefits for the maintaining of adequate supply in intervals when demand is high. The completion of advanced meter deployment will allow further market innovation for the provision of residential and small commercial demand response and any market design modifications should allow full participation of these resources.

Question 2. How far forward should the procurement occur? What are the trade-offs of different forward procurement times?

Procurement should occur with sufficient time to allow generation resources to be built and placed into service, understanding that permitting requirements from federal and state regulators can extend that time, sometimes unpredictably. Three years is generally a reasonable forward procurement timeframe and has been demonstrated sufficient to incentivize generation build in other markets. A significantly shorter procurement time may not be feasible given the time necessary to resolve permitting issues, particularly securing the environmental permits necessary for operation. Significantly longer procurement times are problematic because the difficulty of correctly predicting long-term supply and demand may distort the match between what demand is projected and what supply is actually delivered.

Question 5. Should a transition mechanism be considered? If so, what issues would a transition mechanism be intended to address and how should it be structured?

Any transition to a new market design must account for the fact that the great majority of customers in the ERCOT market are on term contracts, many with fixed prices for periods of months or years. If new costs are to be imposed in the market during the pendency of existing contracts, there must be a mechanism to allow those costs to be recovered through a change of law or other provisions so that the REPs can continue to serve their customers. Failure to allow REPs to recover new costs from existing contract customers will likely result in intolerable reduction in liquidity in the market which will further exacerbate the price increases to customers that will result from the introduction of new costs to secure future generation capacity.

Question 7. How would the reliability obligation be allocated to load serving entities?

If there is a mandate for capacity associated with a reserve market above what the market will deliver, the Commission should evaluate all options for recovery of that reliability obligation and not necessarily limit such charges to load serving entities. The market should explore all potential options for recovery of the costs of an administratively determined reserve margin. If that obligation is charged directly to LSEs, the Commission should explore the option of charging these costs on a load ratio share based on an energy usage basis.

Question 9. If the market allows for self-provision, how should that be structured?

Self-provision should only be considered for non-opt in entities that are not participating in retail competition. Load in competitive areas should not be allowed to participate in self-provision as they are not allowed to own generation resources. Allowing competitive entities with generation affiliates to participate in self-provision will likely cause market power abuse problems as REPs with generation affiliates will be placed at a competitive advantage that will be impossible for independent REPs to overcome. Specifically, generator-affiliated REPs would effectively be able to opt-out of paying for resource adequacy by obtaining self-supply from their affiliate while independent REPs would have no such option and would bear an increasing proportion of resource adequacy costs. The self-supplied generation to competitive REPs would be effectively removed from the available resource supply, further increasing prices for resource adequacy obligations.

Commissioner Anderson Questions

Question 10. What is the average value of lost load (in $/MWh) in the ERCOT market?

The average value of lost load (VOLL) cannot be determined without further study in the market. To the extent VOLL is used as an input in ORDC, it appears that the maximum VOLL that used should be closer to $9 thousand than the other values that have been discussed and is likely considerably less. A look at the limited number of intervals where the price of electricity has reached the system-wide offer cap (SWOC) over the past five years demonstrates that demand is reduced before the cap is reached in all but a small number of intervals. Because the cap has been significantly lower than $9 thousand during that period, it is likely that the VOLL is significantly lower as well. Importantly, VOLL varies significantly by customer class and failure to distinguish between industrial, commercial, and residential VOLL will unnecessarily inflate VOLL as the higher customer class value will be applied to all of the load in the ERCOT market.

Question 14. What is the cost of eliminating resource adequacy related outages per MWh under each of the following:

a. a capacity market;
b. EOM plus construction of state-owned generation; and
c. any other backstop or supplemental generation mechanism?

The estimation of costs for different resource adequacy market design changes is better made by ERCOT.

Question 23. How could a mandatory reserve margin be imposed on LSEs?

There are a variety of means by which the cost of a mandatory reserve margin above what the market provides could be charged to market participants. To the extent this margin is directly assigned to LSE's, it is important to ensure that to the extent this cost cannot be hedged, there is a means by which this cost can be recovered in customer charges.

In addition, during the short term transition period it will be important that any such charges that could not have been priced into existing charges be able to be recovered.

Question 30. What performance requirements should be imposed on capacity bidders beyond an obligation to bid in the day ahead market (DAM)?

a. **What additional measures should be imposed to prevent market power abuse by large generators and IPP generators that are affiliated with LSEs?**

The market stakeholder groups will need to examine this issue in the specific context of any proposed market design changes. Market power abuse concerns can be addressed by requiring all LSEs participating in the competitive market to purchase capacity from the auction and not allowing LSEs affiliated with generators to purchase capacity directly from those affiliate generators. No market participants other than municipal utilities and electric cooperatives in non-opt-in areas can be allowed to opt-out of the capacity auction.

Question 31. Should any working group at ERCOT which recommends protocols to implement any mandatory capacity construct be composed at a minimum equally between resources and load?

All market participants in the ERCOT structure should participate in any working group that will implement a mandatory capacity construct or any other significant market design change. The current market process with PUC oversight does not need to be disrupted.

Question 32. How would the costs of a mandatory capacity market be allocated?

It is frequently assumed in the discussion of a mandatory capacity market that costs would be allocated on load ratio share based on peak demand. The market and the Commission should work together to explore all options for assignment of costs associated with a mandatory reserve margin. If a centralized capacity market is adopted, the Texas construct should do better than PJM which allocates based on an annual capacity tag on every meter that is often inaccurate and outdated for significant periods of each year. A seasonal allocation or assignment on load ratio share of energy could be preferable to an annual tag. Importantly, whatever type of load ratio share might be adopted it should be applied centrally by ERCOT and not differently in every TDSP service area with each TDSP applying its own methodology that may result in significantly different shares across the ERCOT market.

Question 33. If a mandatory capacity market contains a forward component, how are payments to be applied to customers who switch? How do REPs allocate their capacity charge? Will REPs be left with what amounts to a stranded cost?

The capacity charges must be assigned by ESID so that the charges flow through to the REP that is the REP of record. In PJM today, assignment of capacity charges is based on historic peak load. In the PJM markets, REPs have historically performed estimations and attempt to recover this capacity charge through a per kWh charge to customer. This mismatch of how charges come to the REPs vs. how the REPs charge customers creates the potential for REPs to be assigned capacity charges that are not recovered from the customer. This is a factor of both changes in overall demand from year to year and changes in demand for each month. If a customer switches at a time when consumption is lower than the average of historic peak demand, the REP will be left with unrecovered costs.

It would be preferable for this Commission to leave it to the discretion of the REP on how to recover these costs from customers. A recent case in Pennsylvania highlights this concern. In Pennsylvania, the ongoing case explores whether or not a product can be called fixed if it includes a pass-through of capacity auction charges.

Question 41. If the market includes a centralized or residual auction, how should the auction be structured?

The residual auctions result in changes to capacity charges that occur in the middle of retail contracts. REPs must have the option of passing through any changes resulting from these residual auctions to customers on fixed price contracts.

Question 44. What additional elements of a reliability market design should be considered?

The discussion of various reliability market designs often does not address the customer side of equation. Most customers in the ERCOT market – particularly residential and small commercial customers – are on fixed price term contracts for a period of months or years. This limits their exposure to fluctuating market energy prices. In addition, the customers have the option today of choosing average pricing that is not sensitive to real-time prices or they have the choice of a wide variety of products that incorporate directly, or indirectly some recognition of peak pricing. For example, customers can choose products that incent load shifting to weekends or nights by offering reduced pricing during those time. In addition customers have options in the market today of choosing plans where some or all of their price is based on time-of-use and real-time pricing. Further, end-use customers today have the option of participating in a variety of voluntary load response programs. REPs in the market continue to introduce innovative products to reward customers that exercise control over their energy use to shift use to lower cost intervals. To the extent that pass-through costs to maintain reliability are introduced they need to be considered in context of the customer's entire bill for electricity and recognize that the higher in proportion the reliability cost becomes, the less apparent the advantages of a competitive market become.

If the Commission elects to pursue a forward capacity market then the pass through of capacity payments by REPs should be allowed in same manner as TDU charges. Depending on the specific structure of such a market, it may require an amendment to the product definitions that are currently in the Commission's rules. The cost impact of any market design modification should be modeled so that an understanding of the effects of a decision can be considered prior to implementation. This is also true of multiple market design modifications that are implemented in concert. The System Wide Offer Cap (SWOC) was increased in increments by the Commission in order to raise forward energy prices and incent generators into the market. As the Commission is aware, a high SWOC creates volatility in the market, has credit implications for market participants with ERCOT, increases hedging costs, and will not achieve a specific resource adequacy target.

If administratively-determined payments to generators are required for ERCOT to meet an acceptable level of resource adequacy, then the market and the Commission should revisit the current system-wide offer caps for energy to determine the optimal balance so that consumers are not placed in the "worst of both worlds" by paying for capacity all year long and being subject to unnecessary risk premiums associated with volatile energy costs.

III. Conclusion

TEAM appreciates the opportunity to offer these comments and the comprehensive dedication to this issue demonstrated by the Commission, Commission Staff, and ERCOT market participants. It is imperative the Commission address the issues of the retail side of the power supply chain at the policy stage of decision-making. Otherwise, the Commission could unnecessarily be left with unintended consequences of customer and market impacts if these issues are held-back and not considered up front.

Respectfully submitted,

Catherine J. Webking
State Bar No. 21050055
(512) 542-7036
(512) 542-7236 (Fax)
cwebking@gardere.com

Andres Medrano
State Bar No. 24005451
(512) 542-7013
(512) 542-7223 (Fax)
amedrano@gardere.com

GARDERE WYNNE SEWELL LLP
600 Congress Avenue
Suite 3000
Austin, Texas 78701-2978

ATTORNEYS FOR TEXAS ENERGY ASSOCIATION FOR MARKETERS