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REVIEW OF MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3)	§ § § §	**PUBLIC UTILITY COMMISSION** **OF TEXAS**

TEXAS ENERGY ASSOCIATION FOR MARKETERS' RESPONSE TO COMMISSION QUESTIONS

Texas Energy Association for Marketers (TEAM)[1] files this Response to Commission Questions. TEAM appreciates the willingness of the Public Utility Commission of Texas (Commission) to carefully consider the impacts of all potential options for incentivizing and supporting the development of additional flexible dispatchable generation to address reliability needs of the grid, while continuing to allow Texans to have access to a competitive retail electricity market that provides customers with choice and innovation.

The status quo with the Electric Reliability Council of Texas's (ERCOT) "conservative operations" must change. Wholesale market prices for energy have far exceeded the cost of new entry (CONE) for some time now. Ancillary Service costs have increased substantially, and liquidity in these markets makes it difficult to hedge economically for residential and small commercial customers to determine appropriate risk premiums in fixed prices. ERCOT's actions indicate a need for new, flexible dispatchable generation resources to meet the operational reliability requirements for the grid.

I. RESPONSES AND COMMENTS

1. ***The E3's report observes that the PCM has no prior precedent for implementation, does this fact present a significant obstacle to its operation for the ERCOT market?***

Yes. While new concepts to customize options to the ERCOT market will always be important, the fact that no prior precedent exists in any other electricity market presents concerns given the particular circumstances of the ERCOT wholesale and competitive retail electricity markets. The lack of precedent creates risk of timing, cost, and ultimate success of

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[1] The TEAM members joining these comments include: APG&E; Chariot Energy; Demand Control 2, LLC; Frontier Utilities, LLC; Fulcrum Retail Energy, LLC; Gexa Energy, LP; Just Energy Texas, LP; Rhythm Ops, LLC; Shell Energy Solutions; and Tara Energy, LLC.

implementation. This prolonged lack of stability could result in continued freezing of investment in ERCOT and increased costs to customers.

In addition, the E3 Report assumes that ERCOT implements real-time co-optimization (RTC) and relies on that dispatch mechanism to support the proposed award of performance credits. ERCOT documents indicate that it will likely take several years to fully implement RTC from the date on which the Commission issues the final order to proceed with this market change. The PCM model, with no prior precedent, appears to be severely complicated by these circumstances.

Further, the closest parallels that are available in other markets have not succeeded in accomplishing the common objective of incentivizing developers to build additional dispatchable generation resources. The following are cited as examples of other markets with issues similar to that of ERCOT:

- The Australian wholesale market is commonly referenced as being the energy market most similar to ERCOT. Australia attempted to implement a new market design that placed a capacity obligation on load serving entities (LSE). That effort ultimately was abandoned after it was determined that it could not be designed with safeguards that would be sufficient to prevent the exercise of market power.
- The Midwest Independent System Operator capacity market has reached the cap price—indicating that, despite implementation of a capacity market in the form of an LSE obligation, the market has failed to add new capacity.
- All other Independent System Operators, including PJM and Southwest Power Pool, are still making substantial changes to their capacity markets years after initial implementation to address various issues.

Finally, because the very fundamental components of the PCM proposal are undecided, the length of time it would take to determine the rules and protocols necessary to implement such changes in the market design creates a great deal of regulatory risk currently and in the future. As such, it is likely that the ERCOT market would not see a thawing of the current investment freeze in the development of dispatchable generation resources. In fact, there is precedent in ERCOT for the implementation of significant changes in market design to greatly exceed time and cost estimates. The number of years to implement PCM or FRM or LSEO as discussed in the E3 Report, would perpetuate the lack of stability in the market and continue to make it difficult to support investment for years to come.

2. ***Would the PCM design incentivize generation performance, retention, and market entry consistent with the Legislature's and the commission's goal to meet demand during times of net peak load and extreme power consumption conditions? Why or why not?***

The PCM design in the E3 Report is not consistent with the legislative language in Senate Bill 3, which directs the Commission to ensure that ERCOT procures ancillary and/or reliability services that meet the reliability needs determined by ERCOT. In contrast, the PCM design does not appear to contemplate a procurement of a service by ERCOT and instead puts a capacity obligation on each customer serving entity. Further, using the hours of lowest operating reserves to determine the capacity obligation at does not meet the goal of targeting investment incentives to flexible dispatchable resources. The E3 PCM design would pay credits to all resource types that were online and available at the time the operating reserves were the lowest. So, for example, a significant unplanned outage of thermal resources would cause a drop in operating reserves, but this could be at a time that does not necessarily correlate to high net peak load nor extreme power consumption conditions.

Without more understanding of some of the fundamental constructs of the proposed design, it is not feasible to truly understand the market incentives that it would create. For example, behavioral changes would be expected if PCM credits are only paid to generation that is online or available. This would likely cause changes in operational behavior that do not appear to be modeled. In addition, the E3 model assumes certain market system conditions that do not exist, such as the implementation of RTC. Because it is not yet implemented, we do not know the full effect of a RTC system on the power supplied in the wholesale market.

3. ***What is the appropriate reliability standard to achieve the goals stated in Question 2? Is 1-in-10 loss of load expectation (LOLE) a reasonable standard to set, or should another standard be used, such as expected unserved energy (EUE). If recommending a different standard, at what level should the standard be set (e.g., how many MWh of EUE per year)?***

Senate Bill 3 obligates the Commission to work with ERCOT in determining the reliability needs of the ERCOT system. This legislation does not require the setting of a "reliability standard" in the way that term is associated with capacity markets. It is entirely possible for ERCOT to have sufficient total system capacity to meet total peak load requirements and still have a reliability need for flexible dispatchable resources to cover periods for which there is a great deal of operational uncertainty.

4. ***The E3 report examines 30 hours of highest reliability risk over a year. Is 30 the appropriate number of hours for this purpose? Should the reliability risk focus on a different measure? Defer to IMM?***

ERCOT, with the guidance of the Independent Market Monitor, should determine the uncertainty risk based on a set formula. That formula should be developed using parameters such as known resources and forecasted net load for a wide range of scenarios. With that data, ERCOT should determine the quantity of dispatchable flexible resources that are needed on a seasonal basis to cover the operational risk. The mechanism for ERCOT procurement of these dispatchable flexible resources should be competitively neutral among retail electric providers (REP) and can be explored after better quantification of the reliability need is understood.

5. ***Over what period should the hours of highest reliability risk be determined? A year, a season, a month, or some other interval? At what point in time should that determination be made?***

A retroactive determination of reliability hours is not consistent with a competitive retail electricity market. Because the system behaves differently in the various seasons, it seems that whatever reliability measures are supported, there should be an analysis to determine if they should be adjusted seasonally to meet ERCOT's reliability needs.

6. ***Would a voluntary forward market for generation offers and a mandatory residual settlement process for LSE procurement provide additional generation revenue sufficient to incentivize resource availability in a way that improves reliability?***

More details would need to be understood to meaningfully answer this question. There have been discussions that the forward market would be voluntary, but that resources would only be eligible for Performance Credits if they had been offered in the forward market. That construct is not apparent in the E3 Report. It would be important to understand these fundamentals to evaluate the reliability impacts of the proposal.

7. ***Does a centrally cleared market through ERCOT sufficiently mitigate the risk of market power abuse? Should additional tools be considered?***

As laid out in the E3 report, the centrally cleared market does not mitigate market power concerns. It does not address market power concerns because there is not a must offer component. E3 has indicated that there is not a mandate for quantity or price in the forward market. Therefore, it is expected that the residual market will be the primary place where these capacity credits will made available and clear. For an LSE that does not also have a portfolio of dispatchable generation, this mechanism creates significant financial exposure that could not be tolerated. Essentially, LSE's that don't have affiliates that own generation will be left to pay for capacity credits after the reliability period based on their customers' actual usage along the sloped demand curve that is administratively determined by the Commission.

8. ***If the commission adopts a market design with a multi-year implementation timeline, is there a need for a short-term "bridge" product or service, like the Backstop Reliability Service (BRS), to maintain system reliability equivalent to a 1-in-10 LOLE or another reliability standard? If so, what product or service should be considered?***

The E3 report does not support a determination that the 1 in 10 standard will not be met under the current market design. However, there is an immediate need for an alternative market solution to address the operational reliability needs of ERCOT as discussed by ERCOT and the IMM.

9. ***If implementing a short-term design as a "bridge" delays the ultimate solution, should it be considered? Is there an alternative to a bridge solution that could be implemented immediately, using existing products, such as a long-term commitment to buy the additional 5,630 MW of Ancillary services necessary to achieve the 1-in-10 LOLE reliability standard?***

No response.

10. ***What is the impact of the PCM on consumer costs?***

The PCM will increase customer costs and will decrease options for customers—both in terms of innovation and number of REPs who are able to offer service in ERCOT. Further, the design as proposed by E3 appears to make it infeasible to offer fixed price contracts for residential and small commercial customers unless prices for protected customer classes will be subject to adjustments based on changes in the cost of the capacity credits throughout the term of a contract. In addition, it will increase cost and price certainty for all LSEs and their customers.

Cost of Performance Credits

The E3 Report limits its cost projections to the aggregate wholesale market. The report does not include any analysis of the cost to end-use customers. What the E3 Report does show is that the capacity credits are projected to cost $5.7 billion per year. This cost would be approximately $14.50/MWh (depending on the total grid usage for the year). For a residential customer, even assuming a pure pass-through, this would equate to $17.40 per residential customer per month in performance credit cost ($208.80/year).

Collateral Costs

In addition, it is not a reasonable expectation to assume a pure economic pass-through of the direct cost of the Performance Credits. A REP would also incur costs that are less transparent such as the cost of collateral postings that will be required for expected performance credit obligations; increasing the costs to serve customers in ERCOT. If a REP buys the credits on a forward exchange, there is a requirement for those credits to be paid for in advance, before the customer receives service, or a collateral will have to be posted to the seller to account for future fluctuations in prices. If the REP is unable to buy the credits on a forward basis, it is expected that ERCOT would add the cost of performance capital credits to the collateral requirements for all LSEs. Depending on the calculation, this would increase the cost to serve customers and could be cost prohibitive for REPs and other LSEs who do not have an affiliated interest that supplies sufficient credits to match the projected load of the LSE. These collateral costs will determine the feasibility of a market participant to remain in the market and offer service to customers.

Under the current wholesale and retail market constructs, a REP is able to manage collateral costs at ERCOT with firm scheduling of power through a bilateral agreement. While REPs are able to enter into wholesale energy supply contracts to match the term of the customer's fixed price contracts in today's market design, the upfront collateral is often mitigated by a right of the wholesale supplier to assume the retail customer contract as collateral. This has economic rationality because the customer's retail contract corresponds in timing and quantity to the wholesale energy purchase. However, the PCM obligation does not directly correlate to the customer's usage because the settlement interval (i.e., day and time) that the obligation will be measured is unknown at the time of execution of the contract with the customer. In fact, the PCM obligation, in both quantity and price, remains unknow even after the customer is provided service and billed for usage. The look-back feature of the PCM to determine the obligation and the price adds risk and cost for the credits and the associated collateral.

Retail Energy Price Impacts

The E3 Report assumes a reduction in real-time settlement point prices for energy if the PCM were implemented; however, REPs buy power for their customer contracts in the forward bilateral energy market. There is no analysis that supports a quantification of how much, if any, reduction would be seen in the cost of firm wholesale energy contracts in the bilateral markets. Further, the implementation of this disruption in the market design is expected to invoke change in law provisions that would require renegotiation of existing firm supply contracts for most if not all LSEs. The business disruption and transactional costs associated with this level of change have not been addressed or quantified in the E3 Report.

Costs to Design and Implement

It is important to realize that customers will also bear the cost of implementation of any major system changes at ERCOT. The cost of implementation would involve direct costs at ERCOT as well as costs for each market participant to adapt to potential changes, modify wholesale and retail contracts etc.

A review of the cost and time to implement the conversion from zonal to nodal may help to inform the risk of this customer cost. A summary of the Nodal Implementation cost and timing was provided by the Commission in its Scope of Competition Report to the 2011 Legislature:[2]

Preparations for Nodal Market

The Commission adopted a rule in August 2003 directing ERCOT to implement a nodal market design and in April 2006 approved the Protocols for the operations of the nodal market. The rule contemplated that the nodal market would begin operating in January 2009. ERCOT subsequently delayed the nodal market launch and in November 2008 ERCOT established December 2010 as the new launch date. The estimated budget for completing the nodal market

[2] PUC Report to the 82nd Texas Legislature; Scope of the Competition in Electric Markets in Texas at 4-25.

design increased from $319.5 million in February 2008 to $510.1 million in March 2009. As of the end of November 2010, ERCOT had actually spent $523.4 million, with an additional $13 million in interest charges, and $25 million set aside for nodal stabilization efforts after market launch. ERCOT conducted extensive market trials throughout 2010 to test the new system and successfully launched the nodal market on December 1, 2010.

The ERCOT cost of nodal implementation resulted in a surcharge on all MWhs for many years. The overall time and scope of the cost of any potential market design implementation should be better understood before the cost to customers can be reasonably estimated.

11. ***What is the fastest and most efficient manner to build a "bridge" product or service, such as the BRS, in order to start sending market signals for investment in new and dispatchable generation, while a multi-year market design is implemented by ERCOT? Please provide specific steps.***

Any investment in a generation resource will require a capital investment with an expected payout period that extends out many years into the future. In order to create incentives for such an investment, the revenue model must be able to project revenues for at least 10 years. If there is an untested and unspecified direction of PCM the ERCOT market will be subject to many years of regulatory risk and uncertainty that will complicate and frustrate the market in such a way that it will be nearly impossible to develop revenue projections that would support such a long-term investment.

The Commission should consider adopting a solution consistent with SB3 along the lines of the Coalition proposal immediately. It is also important that the Commission provide regulatory certainty signals to investors and indicate that without statutory change, the investors can expect the valuation of their resources to be governed by competitive forces.[3]

Based on the information presented by the IMM and the cost considerations outlined here, a revised market design that takes multi-years to develop and then more years to implement appears to be unwarranted.

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[3] PURA § 39.101.

12. ***In what ways could the Dispatchable Energy Credit (DEC) design be modified through quantity and resource eligibility requirements, e.g. new technology such as small modular nuclear reactors, in such a way that it incentivizes new and dispatchable generation?***

Whatever incentives are created, they should target revenues to the incremental need for dispatchable flexible generation through a mechanism consistent with the principles discussed in these comments.

II. CONCLUSION

TEAM appreciates the opportunity to work with the Commission to ensure the reliability needs of ERCOT are met in compliance with Senate Bill 3. TEAM reiterates that the tenets of the underlying legislation remain in effect and should govern any Commission (or ERCOT) action: The prices production and sale of electricity should be determined by customer choices and the normal forces of competition. It is in the public interest for Texas to have a competitive retail electric market that allows each retail customer to choose the customer's provider of electricity and that encourages full and fair competition among all providers of electricity

TEAM looks forward to continuing to work with the Legislature, the Commission, ERCOT, and all market participants to ensure that customers continue to benefit from the competitive retail electric market.

Respectfully submitted,

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ATTORNEYS FOR TEXAS ENERGY ASSOCIATION FOR MARKETERS

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EXECUTIVE SUMMARY

- The E3 Report speaks only to aggregate wholesale market costs, and does not examine the impacts on customer cost, product offerings or quantity and quality of retail choice offerings that might be possible under any of the market design changes examined in the report.
- More fundamentals must be understood and studied in order to determine the cost impacts to the end-user under any of the capacity market options in the E3 Report.
- Any design should allow retail electric providers to understand and manage the cost of any reliability measure at the time the customer signs a contract.
- The E3 Report does not present an option that satisfies the obligation of Senate Bill 3 for the establishment of an ancillary or reliability service for procurement by ERCOT to satisfy the reliability needs of ERCOT.
- Current operating conditions at ERCOT demonstrate a need for new dispatchable flexible generation at ERCOT.
- The PCM (and other capacity market constructs in the E3 Report) do not address current ERCOT reliability needs, and further consideration of these sweeping changes could delay the ability of investors to bring generation resources to the market.
- The PCM (and other capacity market constructs in the E3 Report) would take years to design to fit ERCOT and then more years to implement.