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PROJECT NO. 54335

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

TEXAS OIL & GAS ASSOCIATION'S REVIEW OF MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3) COMMENTS

The Texas Oil & Gas Association (TXOGA) appreciates the opportunity to comment on Project No. 54335, Review of Market Reform Assessment Produced by Energy and Environmental Economics, Inc. (E3), commissioned by the Public Utility Commission of Texas (PUC).

TXOGA is a statewide trade association representing every facet of the Texas oil and gas industry including small independents and major producers. Collectively, the membership of TXOGA produces in excess of 80 percent of Texas' crude oil and natural gas, operates over 80 percent of the state's refining capacity, and is responsible for the vast majority of the state's pipelines. In fiscal year 2021, the oil and natural gas industry supported more than 422,000 direct jobs and paid $15.8 billion in state and local taxes and state royalties, funding our state's schools, roads and first responders.

TXOGA members care deeply about the cost and reliability of electricity, as much or more so than most other classes of consumers. Most, if not all, TXOGA members buy electricity from the grid. While some members generate a portion of their electricity, most do not. Operators that do generate a portion of their own electricity are still exposed to ERCOT's pricing and reliability. A large refinery, for example, can easily spend tens to hundreds of millions of dollars on electricity purchases each year. Electricity can be one of the largest operating expenses for most TXOGA members.

As for reliability, all TXOGA members are reliant on ERCOT to maintain the reliability at their own facilities - including those with their own generation. That is because most self-generation cannot be operated without a functioning grid. Moreover, TXOGA members are often more sensitive to grid disruptions than other types of consumers. Any interruption in grid service, even for a second, can cause the shut-down of facilities. Such unexpected shut-downs impose all sorts of risks - from environmental to personnel safety, and financial impact. Unlike many other consumers, when a TXOGA member facility shuts down due to such a grid disruption, it could take hours to weeks to fully restore safe operations.

There is a portion of TXOGA members with self-generation that can also support the grid's reliability while reducing overall grid costs. Self-generating members may sell power to the grid, supply ancillary services, provide grid inertia, and reduce their own load during critical periods. These operational practices mean results in more capacity to the grid and greater flexibility. One important point to note about operators with self-generators, they prioritize the support of their operations first and foremost and are not concentrating on taking advantage of volatility in the Electric Reliability Council of Texas (ERCOT) market.

Introduction

The ERCOT region, even more than many other electrical grids around the country, is increasingly challenged by rapid changes in grid resources and customer demand. Texas's population and energy demand is increasing more rapidly than almost anywhere else, but additional supply is increasingly being provided by intermittent generation. The impacts of this rapid change are large, complex, and need to be evaluated to ensure that meet all of Texas' needs.

Market design changes implemented to date (Phase I) have focused on short-term solutions designed to help stimulate the market. While these changes have been expensive, we do not know if they have cost effectively improved long-term reliability. Changes to the Operating Reserve Demand Curve (ORDC) and the system-wide offer cap, increases in ancillary service procurement, conservative implementation of Reliability Unit Commitment (RUC), increased funding of the Emergency Response Service (ERS) and development of a firm fuel service have all been enacted to increase funding of generation resources, but with little ex ante or even ex post analysis of cost and benefit.[1]

Now, in support of the next phase of market design changes, the PUC has sponsored the E3 Assessment of Market Reform Options to Enhance Reliability of the ERCOT System study, completed in November 2022. TXOGA commends E3 and PUC for addressing the two major issues in ERCOT—cost and reliability—head on, and for thoughtfully seeking new solutions to our growing problems. But the significant market redesign decisions that the PUC is now considering are material with respect to both cost and reliability and would benefit from much more analytical rigor than has been presented to date. In addition, the PUC should keep all options on the table, most notably by assessing the market design changes proposed by the ERCOT Independent Market Monitor (IMM)[2] and by the Coalition for Dispatchable Reliability Reserve Service (DRRS Coalition)[3] as well as considering the potential for competitively bid direct procurement of new flexible dispatchable generation[4].

The analytical model used in the E3 analysis is specifically designed to determine the likelihood of insufficient resources to serve customer demand in the planning horizon, in other words, the likelihood of future "Loss-of-Load" events. Per this analysis, the generation fleet in ERCOT <u>today</u> is close to the 0.1 days/yr benchmark,[5] and TXOGA agrees that installed capacity was not the issue during Uri. Any market proposal that works only to increase capacity indiscriminately without considering the specific reliability needs of the ERCOT region should be seen as unlikely to help improve future reliability, and certainly not in a cost-effective manner.

Here are comments TXOGA would like to highlight regarding this study:

- The analytical model used in the E3 analysis is not designed to provide an assessment of individual unit market revenues or market viability. Rather, the SERVM model used in the analysis was designed to evaluate the likelihood of loss of load events due to inadequate resources to serve expected customer demand. This model has been expanded in recent studies conducted by the Brattle Group and Astrape Consulting to calculate the reserve margin in ERCOT at which there would be sufficient return on investment to incentivize construction of new generic generation capacity. The likelihood and timing of actual unit retirements are highly unit-specific, and the analysis conducted by E3 is insufficient to draw any conclusions regarding near-term unit retirements. Yet the output from this model is used to

[1] Time stamp 2 hours 10 minutes into House State Affairs hearing (12/5/22)
[2] https://interchange.puc.texas.gov/Documents/52373_178_1160003.PDF
[3] https://interchange.puc.texas.gov/Documents/52373_384_1258736.PDF
[4] TXOGA recognizes that competitively bid direct procurement might not be within the PUC's authority, but the PUC must consider possible actions by the Legislature.
[5] E3 report, page 7

justify the assumption that over 17% of the existing thermal generation fleet (over 11 gigawatts) is likely to be retired and removed from service in the near future, leading to unacceptable levels of customer outages (i.e., loss-of-load events) and the conclusion that the current energy-only market is not a viable alternative. Only by "adjusting the 2026 portfolio into market equilibrium" [i.e., assuming the retirement of 11,560 MW of firm capacity] does the 2026 portfolio fall short of the 0.1 days per year reliability standard.[6] In comparison, a recent parallel study conducted by ICF assumes only 2.9 GW of retirements by 2027.[7] Moreover, the IMM was recently quoted as saying, "We don't see 11,000 megawatts of retirement."[8] If it is true, as the IMM and ICF assert, that E3 overstated thermal retirements, then the current market design's future performance will also be understated. The PUC should revisit the model in light of the IMM's critique and ensure projected retirements are accurately stated to permit a fair comparison with proposed alternatives.

- The E3 modeling analysis also relies only on weather data from 1980-2019 data and (1) does not expressly include Winter Storm Uri (although there were significant winter storms in both 1989 and 2011) and (2) does not include the potential for future weather conditions more extreme than what is included in the historical dataset, a limitation that E3 expressly recognizes.[9] Rather, the analysis implicitly assumes that future weather conditions will have the same variability as observed across the 40 historical years from 1980 - 2019.[10] It is important to keep these limitations in mind and understand that unexpected weather variability could result in significantly different outcomes than what E3 modeled.
- It is not clear from the report whether E3 considered improvements in technology (e.g., wind and solar capacity factors, storage cost and performance). It is also not clear how the modeling analysis addressed battery storage operations nor the expected increase in storage resources on the grid.
- The 0.1 days per year of LOLE standard in the E3 report is thought by the IMM to be, "unjustified based on any reasonable VOLL (we have estimated it implies a $200,000 VOLL)." The IMM considers the possibility of "a VOLL of roughly $20,000 per MWh" which it says "is reasonable based on relevant studies."[11] E3 should analyze the LOLE implied by such a lower VOLL, and PUC should determine whether such a lower LOLE meets the reliability standard expectations of Senate Bill 3.
- The E3 study authors specifically do not recommend the Performance Credit Mechanism (PCM) option, finding that it is too risky[12]. In particular, compared to other, more established structures, the unintended impacts of the PCM proposal on the ERCOT wholesale and retail energy markets are more difficult to accurately assess given the PCM's novelty.
- Given the significant questions that remain, the total cost of the PCM (as well as the other forward capacity constructs proposed by E3) needs to be very carefully considered. E3 estimates that the LSERO, FRM, and PCM market designs would cost approximately $5.67B/year.[13] E3's analysis concludes, however, that these market designs will result in an incremental capacity of 5.6GW of natural gas capacity relative to the energy-only portfolio, reducing energy and ancillary service costs and resulting in the net cost of PCM being $460M/year. But this net cost projection is premised entirely on modeled new thermal capacity. If the study assumptions and model output are wrong, Texas could wind up with a costly redesign of the ERCOT market that doesn't improve long-term reliability.

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[6] Ibid, page 46
[7] https://interchange.puc.texas.gov/Documents/52373_380_1248378.PDF, page 48
[8] https://www.houstonchronicle.com/business/energy/article/Lawmakers-worry-consumers-could-be-big-loser-in-17593110.php
[9] E3 report p. 34
[10] Ibid, page 34
[11] https://interchange.puc.texas.gov/Documents/52373_178_1160003.PDF
[12] E3, page 9
[13] E3, page 6

TXOGA urges the PUC to think carefully before implementing a risky and untested market design, and to consider whether less uncertain and more established market design alternatives, such as the ones recommended by the IMM and the DRRS Coalition, would produce similar results.

- Another challenge with many of the proposals evaluated in the E3 study is that they will take so long to implement and would likely delay investment in new resources because of the multi-year market uncertainty that they would create and, thereby, undermine reliability. E3 itself acknowledges that the LSERO, FRM, and PCM all have a minimum implementation time of 2 to 4 years. At a minimum if the PUC implements the LSERO, FRM, or PCM, it is imperative to consider what additional market design structures (such elements as the IMM's Uncertainty Product or the DRRS Coalition's proposal can bridge the gap between now and the implementation.
- Finally, TXOGA strongly recommends that PUC expressly consider and add to their analysis the IMM's proposal for an Uncertainty Ancillary Service Product. While we have not yet seen analysis indicating the impact of the Uncertainty Product, the IMM believes such a product could lower non-spin costs, be co-optimized with energy and other ancillary services, and reduce ERCOT's reliance on out-of-market actions. In addition, as an ancillary service, the Uncertainty Product can be implemented rather quickly and relatively seamlessly into the current ERCOT market avoiding the risks of unintended consequences that could result from the PCM. The IMM's proposal should be given the same thorough analytical vetting and compared against other alternatives in cost and reliability benefits. Texans deserve to have all options on the table.

Recommendations

- Despite the significant outstanding questions about the E3 study and the IMM's proposal, TXOGA strongly agrees with the PUC that ERCOT is facing reliability risks that should be addressed. As ICF stated in their report, there are significant risks of prolonged and numerous outages if no action is taken.[14]

- Accordingly, we propose that the PUC further study the recommendations in the E3 report with the additional analytical rigor that, so far, remains lacking as we have highlighted above.

- We further propose that the PUC explore other potential market design changes that may be less costly, quicker to implement, fit better within the existing market structure, and and/or better target the true issue, i.e., the performance and flexibility of the resource fleet and not capacity. The IMM's Uncertainty Product proposal needs full consideration. It could be implemented as an ancillary service as part of the Day-Ahead Market, and since it would simply be a new ancillary service, it would easily fit within the current market design. The PUC should also consider the possibility of competitively bid direct procurement of new flexible dispatchable generation.

- Reliability standards, including whether the 0.1 LOLE standard remains appropriate, are a bigger conversation and the establishment of any such standard(s) must have broad stakeholder review and support in order to serve Texas and the Texas economy well.

- Finally, the PUC needs to be able to assure the market that any change will bring regulatory certainty. Without that, any proposed changes will not have the perceived stability necessary to incentivize the desired investments.

In response to the questions posed by PUC staff:

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[14] ICF, page 6

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, TXOGA sees that it is a very significant obstacle that the PCM model has no precedent for implementation.

E3's report itself raises significant arguments against the PCM as a prudent market reform.

- The qualitative risks with the PCM are great: long implementation timeline, high complexity, no prior precedent, and only moderate potential to address extreme weather.[15]
- As E3 acknowledges, the market will need time to respond to the market signals created by this new product.[16] The less broad-based the stakeholder support, the more hotly contested the drafting of the rules; extending the implementation time and the uncertainty that will delay investor response.
- A PCM mechanism has not been implemented in any electricity market in the world to-date.[17] Therefore there are no pre-tested constructs around which stakeholders can quickly coalesce.
- Implementation of the PCM entails significant risk because of its novelty and the potential for unintended consequences or unexpected challenges in the definition and implementation of market rules could undermine a successful implementation.[18]

Not noted in E3's report but equally significant are the assumptions and modeled output around market economics and generator retirements/additions. If any of these inputs or outputs departs significantly from reality, Texas may pay more for little benefit. That modeling risk is present with any predictive market redesign, but risk is greatest with the PCM because it's the least tested.

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?

TXOGA believes that the PCM might not incentivize performance, retention, and market entry at a reasonable cost compared to alternatives and that more analysis of E3's alternatives and the IMM's Uncertainty Product is needed to determine if there are better alternatives that could likely provide better incentives and/or lower costs.

Again, E3 makes sufficient arguments to show that choosing the PCM against alternatives, without further analysis, would be premature.

- Performance credit (PC) awards are unlikely to be predictable on a forward basis and so may not adequately incentivize performance or market entry any more than a well-designed energy and ancillary services market. Per E3, in any individual year, the quantity of PCs generated will deviate from expected value based on weather conditions, plant outages, and other factors.[19]
- The PCM is less able to reflect infrequent extreme weather conditions because it is assessed each year based on actual conditions that may not reflect any extreme weather.[20]
- E3 acknowledges that the PCM will overcompensate resources during mild years, even if they are not able to reliably perform during extreme weather events.[21] That's worth restating - the PCM will require

[15] E3, page 76
[16] E3, page 82
[17] E3, page 91
[18] E3, page 121
[19] E3, page 58
[20] E3, page 8
[21] E3, page 87

ratepayers to pay generators when reliability services aren't needed without being sure those same generators will perform when they're needed most.

Beyond the E3 report itself, there are concerns about incentives (in particular, the likely significant number of hours in which PC would be awarded that would result from unit forced outages, which by definition cannot be predicted) and whether the PCM could be gamed by generators by manipulating outages.

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 kWh of EUE per year)?**

TXOGA believes that any consideration of a reliability standard must be a conversation had amongst stakeholders and not decided in this process due to the complexity of the discussion and the likely many divergent opinions that currently exist. Any reliability standard target must have broad based stakeholder support to have any value. That said, TXOGA believes that it is critical to consider the value of lost load (e.g., the IMM's $20,000/MWh) when considering market changes as that provides the basis for weighing the benefits of incremental improvements in reliability against the costs.

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?**

TXOGA believes that, at a minimum, the PCM needs to be evaluated against alternatives before considering it further. That said, should the PUC move forward with the PCM, the number of hours and the distribution of hours throughout the year would be a critical design component. Even with as few as thirty hours, in some years there could be hours in which PCs are awarded to resources for performance during hours in which there was no reliability risk to the grid. That's a downside of the PCM that cannot be designed out.

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?**

TXOGA believes that, at a minimum, the PCM needs to be evaluated against alternatives before considering it further. That said, should the PUC move forward with the PCM, the shortest number of hours will be the most effective at matching the actual need to the amount being spent.

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?**

TXOGA believes that, at a minimum, the PCM needs to be evaluated against alternatives before considering it further. Any proposed forward market for generation is in that sense a capacity market and must be compared against the downsides we have seen in existing forward capacity markets.

The flaws with existing forward capacity markets are many and demonstrated in other electricity markets. We need to make sure those flaws aren't repeated here. Proposing a capacity market is a misdiagnosis of the challenge faced during Uri and moving forward, i.e., performance more than capacity. Performance is an operational characteristic that's only measurable in real-time. A forward capacity market, on the other hand, is a tax on electricity consumers with the purpose of reducing market risk to generators.

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

TXOGA believes that the PCM needs more consideration and evaluation against alternatives. That being said, any forward generation market, no matter how it's designed, introduces new opportunities for market power abuse. A perfect example of the potential for market power abuse in the MISO capacity was recently in the news. In that case, an independent power producer is alleged to have manipulated the market so much in just one year that the Illinois Attorney General is seeking to recover more than $400M.[22] Similarly, based on the current descriptions of the PCM implementation, it seems likely that unexpected unit outages will be a significant concern. Any advance knowledge by a large generator of the potential for one of their units to come off-line could lead to an unfair market advantage.

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, to maintain system reliability equivalent to a 1-in-10 LOLE or another reliability standard? If so, what product or service should be considered?**

Yes. For the reasons noted above the PCM takes too long to implement for it to be the only solution. Moreover, any major market change like the PCM which will take years to implement will produce tremendous market uncertainty and disincentivize potential investors. The direct procurement of generation with storage, the IMM's Uncertainty Product, and the DRRS Coalition's proposal merit evaluation to determine whether, in whole or in part, they would be adequate interim and even long-term steps to improving cost and reliability. TXOGA urges the commission to explore all of the recommendations provided earlier in these comments.

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?**

Yes, the costs and benefits of such a hybrid proposal should be fully quantified and considered. All options should be evaluated on cost and implementation. Texas deserves nothing less.

Respectfully submitted,

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[22] https://www.utilitydive.com/news/dynegy-market-manipulation-miso-capacity-auction-ferc-enforcement-vistra-public-citizen/637120/

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EXECUTIVE SUMMARY OF TEXAS OIL & GAS ASSOCIATION'S REVIEW OF MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3) COMMENTS

TXOGA is a statewide trade association representing every facet of the Texas oil and gas industry including small independents and major producers. Most, if not all, TXOGA members buy electricity from the grid. TXOGA members are reliant on ERCOT to maintain the reliability at their own facilities - including those with their own generation. Moreover, TXOGA members are more sensitive to grid disruptions than most consumers.

Market design changes implemented to date (Phase I) have focused on short term solutions designed to help stimulate the market, but with little ex ante or even ex post analysis of cost and benefit. The significant market redesign decisions that the PUC is now considering would benefit from much more analytical rigor. In addition, the PUC should keep all options on the table, most notably by assessing the market design changes proposed by the IMM and by the DRRS Coalition as well as considering the potential for competitively bid direct procurement of new flexible dispatchable generation.

There are several comments TXOGA would like to highlight regarding the study: (1) the analytical model used is not designed to provide an assessment of individual unit market revenues or market viability, (2) the modeling does not expressly include Winter Storm Uri, (3) it is not clear whether E3 considered improvements in technology nor the expected increase in storage resources, (4) the 0.1 LOLE standard is thought by the IMM to be "unjustified based on any reasonable VOLL," (5) E3 does not recommend the PCM option finding that it is too risky, (6) if the study assumptions and model output are wrong, Texas could wind up with a costly market redesign that doesn't improve long-term reliability, and (7) PCM will take several years to implement and would likely delay investment in new resources due to market uncertainty.

TXOGA recommends the following: (1) further study of the recommendations in the E3 report with additional rigor, (2) explore other potential market design changes that may be less costly, quicker to implement, and fit better within the existing market structure, (3) reliability standards are a bigger conversation, and (4) assure the market that any change will bring regulatory certainty.

In response to the staff questions, TXOGA believes that: (1) it is a very significant obstacle that PCM has no precedent for implementation, (2) PCM might not incentivize performance, retention, and market entry at a reasonable cost, (3) any consideration of a reliability standard must not be decided in this process, (4) the number of hours and the distribution of hours throughout the year would be a critical design component, (5) the shortest number of hours will be the most effective at matching the actual need to the cost, (6) the PCM is essentially a forward capacity market and must be compared against the downsides in existing forward capacity markets, (7) any forward capacity market introduces new opportunities for market power abuse, (8) the direct procurement of generation with storage, the IMM's Uncertainty Product, and the DRRS Coalition's DRRS should be studied further, and (9) all options should be evaluated on cost and implementation.