PROJECT NO. 54335

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

COMMENTS OF THE R STREET INSTITUTE

The R Street Institute (R Street) is a nonprofit, nonpartisan public policy research organization headquartered in Washington, D.C. with multiple offices across the United States, including Texas. Our mission is to engage in policy research and outreach to promote free markets and limited, effective government. We believe in the importance of competition within a regulatory framework based on market efficiency. R Street files these comments in response to the Commission's Public Notice of Request for Comments dated Nov. 15, 2022.

Most of the specific questions posed in the Commission's Request are related specifically to the performance credit mechanism (PCM), but subsequent discussion in a variety of forums has made clear that there is not agreement on the problem to be solved. Criticisms of the evaluation of alternate market design proposals performed by Energy+Environmental Economics (E3) focus on the failures that occurred during Winter Storm Uri.[1] To be clear, the Uri-caused catastrophe was not a market design problem. However, reexamining market design is warranted to account for shifts in both the supply and demand characteristics of the Texas electricity industry.

The Commission must begin with defining the issues it wishes to solve. Our comments focus on two problems: 1) avoiding a repeat of outcomes induced by Uri; and 2) improving the efficiency of market design, given changes in the generation fleet and the opportunity to better integrate demand-side participation into the marketplace. This enables the opportunity to identify and compare valid market design options, including the PCM, and dismiss inefficient concepts, such as a new backstop service.

First, it is important to clarify the root causes of the failures during Uri. The Electricity Reliability Council of Texas' (ERCOT) presentation in the aftermath of the storm shows that that aggregate supply during Uri was limited to roughly 50 gigawatts (GW) of capacity.[2] Total installed thermal capacity (nuclear, coal, natural-gas) at the time was roughly 74 GW. After Uri, demands greater than 50 GW have routinely been comfortably served in both summer and less extreme winter conditions. Demand exceeded 50 GW roughly 30 percent of all hours in 2021 after Uri and more than 40 percent of the hours to date in 2022.

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[1] Energy and Environmental Economics, Inc. and Astrapé Consulting, "Assessment of Market Reform Options to Enhance Reliability of the ERCOT System," November 2022. https://interchange.puc.texas.gov/Documents/54335_2_1251718.ZIP.

[2] "Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation," Electric Reliability Council of Texas, Feb. 24, 2021, p. 15. https://www.ercot.com/files/docs/2021/02/24/2.2_REVISED_ERCOT_Presentation.pdf.

Even during the prior firm load shed event in 2011, roughly 52 GW of demand was served, at a time when there was roughly 70 GW of installed thermal capacity.[3]

The energy issues during Uri were generator performance problems, not installed capacity problems: limited fuel and frozen generator supply problems combined with the potential for never-before-seen levels of customer demand, which went unserved due to lack of supply. The Uri-related problems are best addressed via weatherization requirements, increased coordination between the natural gas and electricity industries, and more conservative operations during wide-spread cold weather. Starting up power plants in anticipation of extreme cold weather is a reasonable precaution.

Separately, economic changes affect the long-term outlook of installed capacity, which raises market design questions. As shifting customer preferences and generator costs lead to more variable generation with lower marginal production costs, the challenge of ensuring sufficient supply to meet all demand is increasing and becoming a more complicated problem to analyze. These trends are impacting electricity markets around the world, and to date, it seems that no region has found a perfect market design solution.

Market design choices may be broadly categorized into two types. The first allows the amount of installed capacity reserves to be the result of market forces reaching their own equilibrium. Various market adjustments, primarily related to pricing, can be made to influence actions by market participants with the expectation of influencing the amount of (reserve) capacity available. However, there is no certainty that the actions will achieve a certain magnitude of capacity.

The second type of market design specifies a certain amount of (reserve) capacity to buy. This includes options such as the forward reliability market (FRM), the load serving entity reliability obligation (LSE-RO), defining new ancillary services (AS) or procuring more of existing AS. Although this type of mechanism provides quantity certainty, such quantities are the product of assumptions and projections, and therefore certainty of sufficiency is not guaranteed.

All means of adjusting energy price formation to create incentives for new (or retention of existing) capacity are of the first type. Examples include adjusting the operating reserve demand curve (ORDC) and changing the system wide offer cap (SWOC) and PCM. PCM is in this bucket because there is no requirement to procure a certain number of credits, just an administratively set price that determines their value/cost. Appropriate financial incentives are powerful motivators, but they are merely directional and not precise.

[3] "2011 State of the Market Report for the ERCOT Wholesale Electricity Markets," Potomac Economics, July 2012, p. 16. https://www.potomaceconomics.com/wp-content/uploads/2020/07/2011_ERCOT-SOM_REPORT.pdf

This Commission's review performed by E3 is not the first time the Public Utility Commission of Texas (PUCT) has evaluated fundamental market design changes. An evaluation performed by the Brattle Group in 2012 considered similar market design options and reached remarkably similar findings.[4]

The energy-only market is powerfully efficient and will reach an economic equilibrium. However, that equilibrium point may not include the quantity of installed reserves desired by politicians, regulators or the independent system operator (ISO). The imposition of capacity requirements higher than what would result from economic equilibrium will, by definition, add costs. The real question is whether the increase in cost is warranted by an associated increase in expected system reliability. Using values from the E3 Report dividing the expected cost increase by the improved reliability, as measured by reduction in expected unserved energy (EUE) indicates the value of improved reliability from FRM, LSE-RO and PCM to be roughly $37K per megawatt hour (MWh) and the backstop reliability service (BRS) to be roughly $29K per MWh.[5] These values are within estimated ranges of the value of lost load (VOLL) for various customer types, but are certainly higher than levels ever considered for ERCOT wholesale energy prices. It is likely that there will be disagreement among parties as to whether the incremental reliability value is worth the cost. Structuring the Commission's deliberations around the appropriate value to place on system reliability is likely to lead to a more productive outcome than the current strategy, which seems to be one of reliability (or at least the appearance of reliability) at all costs.

The PCM is a workable framework to add additional incentives for installed (reserve) capacity. Additional discussion, deliberations and decisions will be needed to transform the PCM concept into a detailed design, ready for implementation.

Our responses to selected questions posed by the Commission follow.

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?**

   Implementing a design with no precedent is not an insurmountable challenge. Any significant change to market design will require that ERCOT-specific details be defined.

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?**

[4] Samuel Newell et al., "ERCOT Investment Incentives and Resource Adequacy," The Brattle Group, June 1, 2012. https://interchange.puc.texas.gov/search/documents/?controlNumber=40000&itemNumber=151. Also available at https://interchange.puc.texas.gov/search/documents/?controlNumber=37897&itemNumber=152.

[5] Reliability improvements for FRM, LSERO, PCM and BRS are shown as the same: 1.15 day/year LOLE reduction; 3.4 hours/year LOLH reduction; and 12,461 MWH/year EUE reduction. These are calculated by taking the differences between values in Table 16, p. 47 and values in Table 18, p. 53. Table 22, p. 55 shows the cost increase associated with these reliability improvements to be $460M for FRM, LSERO and PCM; and $360M for BRS. https://interchange.puc.texas.gov/Documents/54335_2_1251718.ZIP.

The PCM appears to provide a new revenue stream for resources, which should provide additional incentive to attract new and retain existing needed capacity. Whether these incentives are sufficient will depend on detailed design aspects related to resource performance requirements and to a larger extent the details of the administratively determined Performance Credit demand-curve.

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)?**

The most important aspect of creating a new market design element intended to improve reliability is to define the reliability standard to be achieved. The use of a 1-in-10 loss of load expectation (LOLE) may be an expedient choice, but LOLE is a dated and increasingly irrelevant metric because it masks the characteristics of potential shortages. As the variability of both demand and supply continue to increase, it will become more important to analyze the specific risks of extreme outcomes, not just include the extreme outcomes in an average with all other outcomes.

One way to address the risks of extreme outcomes specifically is by using a two-part reliability criterion. For example, Belgium uses both an average loss of load hours (LOLH) criterion of 3 hours/year and an LOLH95 criterion of 20 hours/year.[6] Using both helps ensure that even in the most extreme potential scenarios, there will be adequate resources to cover a statistically abnormal year.

The reliability standard for Australia's National Electricity Market (NEM) is 0.002 percent Expected Unserved Energy (EUE).[7] Applying that metric for ERCOT translates to roughly 8,000 MWh of annual EUE. The E3 analysis determined that ERCOT's energy-only market has an annual EUE of 14,093 MWh, and the LSERO, FRM, PCM and BRS alternatives would have 1,632 MWh of EUE. For context, the estimated amount of unserved load during Winter Storm Uri was roughly 900,000 MWh.[8]

Consideration of the appropriate resource adequacy reliability criteria should be performed within the context of all causes of customers' electricity service interruption. The customer impacts of distribution system limitations are typically an order of magnitude higher than 0.1 LOLE. This is clearly shown in data recently assembled by the Commission's Division of Compliance & Enforcement. The Dec. 5, 2022 memo from Barksdale English summarizes

[6] "Mid-term Adequacy Forecast 2020 Appendix 2," European Network of Transmission System Operators for Electricity, 2020, p.14.
ENTSO-E Mid-term Adequacy Forecast 2020: Appendix 2 https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/MAF/2020/MAF_2020_Appendix_2_Methodology.pdf. – Methodology (entsoe.eu).
[7] "Reliability," Australian Energy Market Commission, last accessed Dec. 12, 2022. https://www.aemc.gov.au/energy-system/electricity/electricity-system/reliability.
[8] 15 GW * 60 hours

distribution system reliability standards across Texas.[9] These annual values range from roughly 0.5 to 2.0 outages, with durations ranging from 50 minutes to more than 2 hours. These are the standards. Actual performance is generally worse.

Brattle's recommendation in their 2012 report holds true today:

> We therefore recommend that the PUCT and ERCOT evaluate their resource adequacy objectives in the context of delivered reliability, load shedding protocols, and informed by an analysis of marginal costs and benefits. We recommend determining the desirable reserve margin target and, separately, a minimum acceptable reserve margin needed to avoid extremely adverse consequences under worst plausible weather and outage conditions.[10]

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?**

Determining this duration of highest reliability risk is a Goldilocks dilemma, it needs to be "just right." Selecting too many hours may result in needless actions by loads and resources; too few and actions may be insufficient. It does not appear that E3 performed any historical analysis to help them reach the 30-hour assumption. We recommend that such an analysis be performed to determine the historical number of "high risk" hours in a year. Using the distribution of historical "high risk" hours would help inform the decision about the appropriate number of hours to include.

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?**

We suggest that an annual determination is a good place to start. However, as supply and demand both become increasingly variable, traditional high-risk periods (hot summer afternoons) are likely to no longer be the times of most concern. It will be important to assess the high-risk periods regularly to ensure that incentives for supply and demand actions remain closely aligned with system needs.

We suggest that establishing monthly requirements will be too granular. However, seasonal differences will be important to assess, particularly as weather extremes are a primary driver of many system risks.

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[9] Docket 52937, Item 11, Public Utility Commission of Texas, Dec. 15, 2022. Interchan https://interchange.puc.texas.gov/search/documents/?controlNumber=52937&itemNumber=11ge - Documents (texas.gov).

[10] Newell et al., p. 4. https://interchange.puc.texas.gov/search/documents/?controlNumber=40000&itemNumber=151.

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?**

No response.

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

As proposed, the centrally cleared market would only require generators to submit offers. There has been no discussion of imposing appropriate limits on those offers. With no requirement for generator offers to clear, there is limited incentive for any generator (especially those with market power) to offer below the price established by the demand curve.

As proposed, there is not sufficient mitigation against market power abuse. A mitigation to consider would be to impose a requirement for some Load Serving Entities (LSEs) to submit bids to buy from the forward market. Possibly, this must-bid requirement could only apply to LSEs serving residential customers. In addition to a must-bid for some LSEs, a limitation on the bid/ask spread could also be considered.

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?**

On an interim basis, it is not clear that new generation would be needed or feasible. In the short term, the risk is retirement of existing generation. ERCOT's reliability must-run (RMR) mechanism already exists to keep "needed" generation operating and should be used rather than creating something new of questionable value.

Creating a new Backstop Reserve would require resolution of the same issues that needed to be decided about the recently added firm fuel supply service (FFSS). A number of aspects must be determined, including how much to procure, what resources qualify, and whether payment should be pay-as-bid or clearing price. Additional determinations would have to be made regarding how the BRS capacity would be deployed and at what point in the supply stack. Depending on how the BRS is used, there may also be concerns regarding the effects of transmission constraints on the selection or deployment of the service.

A final thought regarding Backstop Reserves is that the State of California has recently budgeted more than $50 billion in general tax dollars, not revenues from electricity customers, to procure what they are calling Strategic Reliability Reserves.[11] The description of the intent of their Strategic Reliability Reserves seems to reflect how the concept of Backstop Reserves has been described for ERCOT.

As described in Gov. Gavin Newsom's signing message re: AB205:

> The bill creates a State-led Strategic Reserve that will only be used in extreme events such as heatwaves and only as a last resort. The Strategic Reserve will operate on top of and after procurement by load serving entities, including local publicly owned utilities, and does not modify or reduce utilities' obligation to meet reliability requirements set in low and regulation. The Strategic Reserve will be comprised exclusively of new emergency and temporary generators, new storage systems, clean generation projects, and funding on extension of existing generation operations, if any occur.[12]

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 imposition of capacity requirements higher than what would result from economic equilibrium will, by definition, add costs. The real question is whether the increase in cost is warranted by an associated increase in expected generation system reliability. As previously described, the value of increased reliability per E3's analysis is roughly $37K per MWh for FRM, LSERO and PCM, and roughly $29K per MWh for BRS. These values are within estimated ranges of the VOLL for various customer types, but certainly higher than levels ever considered for ERCOT wholesale energy prices.

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.**

   No response.

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?**

   No response.

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[11] Gavin Newsom, AB 205 Signing Message, Office of the Governor, June 30, 2022. https://www.gov.ca.gov/wp-content/uploads/2022/06/6.30.2022-AB-205-signing-message.pdf?emrc=588fa3.

[12] Ibid.

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Respectfully submitted,

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EXECUTIVE SUMMARY OF THE R STREET INSTITUTE

- A PCM or other market redesign is not necessary to prevent a recurrence of a Uri-type event, and would not prevent such a recurrence. The PCM framework would add additional incentives for installed (reserve) capacity beyond the current market equilibrium. Additional discussion, deliberations and decisions would be needed to transform the PCM concept into a detailed design, ready for implementation.

- The value of increased reliability per E3's analysis is roughly $37K per MWH for FRM, LSERO and PCM, and roughly $29K per MWH for BRS. These values are within the estimated range of the Value of Lost Load (VOLL) for various customer types, but certainly higher than levels ever considered for ERCOT wholesale energy prices.

- There is no need to create a new Backstop Reserve Service, even on an interim basis. ERCOT's Reliability Must-Run (RMR) mechanism already exists to keep "needed" generation operating and should be used rather than creating something new of questionable value.

- The use of a 1-in-10 loss of load expectation (LOLE) may be an expedient choice, but LOLE is a dated and increasingly irrelevant metric because it masks the characteristics of potential shortages. As the variability of both demand and supply continue to increase, it will become more important to analyze the specific risks of extreme outcomes, not just include the extreme outcomes in an average with all other outcomes.