Texas Power Report Falls Short On Winter Risks, Other Issues

By **Maria Faconti, Ruta Skučas and Robert George** (December 7, 2022)

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On Nov. 10, the Public Utility Commission of Texas released a report completed by Energy and Environmental Economics Inc. titled "Assessment of Market Report Options to Enhance Reliability of the ERCOT System."[1] The goal of the report was to analyze several potential market redesign options for the Electric Reliability Council of Texas market.

While the report recommended the Forward Reliability Market option described below, the PUCT's chairman and staff have expressed stronger support for the Performance Credit Mechanism option. The PUCT has invited stakeholders to submit comments on the report by Dec. 15.

Since issuance, the report has been criticized, with many questioning whether the options presented really benefit Texas customers, or merely provide a new revenue stream for some generators. The most common critique has centered on the failure of the report to account for extreme cold weather, as seen during winter storm Uri.

If the report is intended to provide options for market reform to prevent a recurrence of the problems that followed winter storm Uri, one would expect Uri conditions to have been studied. Instead, the report appears to offer several costly solutions that may provide limited benefits, if any, for Texans worried about another winter weather event.

In the report, Energy and Environmental Economics Inc., or E3, developed and analyzed six specific market design options, and compared them to the status quo:

- Energy-Only — the status quo option — with implementation of Blueprint Phase I enhancements;
- Load Serving Entity Reliability Obligation, or LSERO, which imposes a mandatory reliability standard that load serving entities must meet based on forecasted pro rata consumption during hours of highest reliability risk;
- Forward Reliability Market, or FRM, which imposes a mandatory reliability standard and a mandatory, centrally cleared forward market;
- Performance Credit Mechanism, or PCM, which imposes a mandatory reliability standard and performance credits awarded via retrospective settlement to available resources and a voluntary forward market;

- Backstop Reliability Service, or BRS, which authorizes ERCOT to purchase backstop resources sufficient to meet a mandatory reliability standard;

- Dispatchable Energy Credits, or DEC, which requires load serving entities to purchase DECs from eligible resources in an amount up to 2% of their annual energy loads; and

- Dispatchable Energy Credits and Backstop Reliability Service, or DEC/BRS, Hybrid, which combines the DEC and BRS options.

Based on its assumptions, E3 concluded that the Energy-Only option would result in 2026 system-wide customer costs of $22.3 billion per year, and a loss of load expectation of 1.25 days per year. This $22.3 billion per year estimate was determined to be the base costs for the ERCOT market in 2026, with the incremental costs associated with any new option being added to these base costs.

Under the LSERO, FRM and PCM options, E3 found that the loss of load expectation would be reduced to 0.1 days per year at an incremental cost of $460 million per year. The BRS option resulted in a loss of load expectation of 0.1 days per year, but at a lower cost of $360 million per year.

The DEC option resulted in an increased loss of load expectation of 2.03 days per year, at an increased cost of $490 million per year. Finally, E3 found that the DEC/BRS Hybrid would achieve a loss of load expectation of 0.1 days per year at a cost of $920 million per year. In all cases, the cost of each option will be borne by consumers.

System Costs and Loss of Load Expectation

	Energy-Only	LSERO	FRM	PCM	BRS	DEC	DEC/BRS Hybrid
Total System Cost (per yr.)	$22.33B	$22.79B	$22.79B	$22.79B	$22.69B	$22.82B	$23.25B
Incremental Reform Cost (per yr.)	—	+$460M	+$460M	+$460M	+$360M	+$490M	+$920M
Loss of Load Expectation	1.25 days/yr.	0.1 days/yr.	0.1 days/yr.	0.1 days/yr.	0.1 days/yr.	2.03 days/yr.	0.1 days/yr.

E3 also found that these cost estimates would change under various scenarios — including, among others, "High Renewable" or "High Gas Price" scenarios. For example, E3 found that

ERCOT's current energy-only market structure lacks a specific reliability standard, which leads to a system that provides insufficient revenue to resources to achieve the 0.1 days/year loss of load expectation — the common reliability standard in other markets.

E3 noted that several mechanisms can provide additional revenue needed for a higher level of reliability, stating that the LSERO, FRM, PCM and BRS options all resulted in increased reliability under substantially similar incremental costs that represent approximately 2% of the total ERCOT system cost. The report further found that the LSERO, FRM and PCM options reduce the variability of annual system costs by not being dependent on potentially uncertain scarcity pricing.

The BRS option preserved the volatility characteristic of ERCOT's current energy-only market, and was thus not favored. Based on its analysis and experience, E3 recommended that ERCOT implement the FRM market design.

However, E3 noted that many market designs evaluated in the report appear capable of improving reliability, stating the LSERO, FRM, PCM and BRS options all yielded improved reliability.

While each option is arguably technology-neutral, they are intended to encourage the construction of more reliable power plants: facilities that can be available when needed during times of high demand, despite weather conditions. This will likely favor gas-fired power plants.

While the report showed the LSERO, FRM, PCM and BRS options provided improved reliability, E3 stated that BRS was not preferred, because it resulted in an out-of-market reliability solution that should only be temporary. The PCM option was considered too risky because of its novelty.

The difference in the LSERO and FRM options is in the market structure created to procure the required quantity of reliability credits. The LSERO option requires load serving entities to purchase through bilateral contracting, while the FRM option uses a centrally cleared auction.

The PCM option also establishes a centrally cleared auction for the forward procurement of reliability credits. Under this option, each load serving entity will have a reliability credit requirement, including associated costs, which will be determined at the end of a compliance period based on that entity's actual share of system load during periods of highest reliability risk.

Under the PCM option, load serving entities must procure performance-based credits from generators at a centrally determined clearing price. These performance credits would be earned by generators based on their availability to the ERCOT system during the hours of highest risk.

The report proposes that the performance credit requirement be a fixed quantity that is determined before a compliance period begins, while the settlement process will occur after the compliance period, based on the quantity of performance credits actually produced.

These credits would be awarded to generators after the compliance period ends, based on a look-back of the generator's availability across a predetermined number of highest reliability risk hours, and generally be aligned with peak net load.

Each load serving entity's obligation to purchase the performance credits is based on that entity's pro rata share of system load during those same highest reliability risk hours.

The PCM clearing price is calculated using an administratively determined demand curve designed to achieve a specific reliability standard. As part of this proposal, an ERCOT-administered, centrally cleared, voluntary forward market would be established for generators and load serving entities to exchange performance credits to hedge against potential adverse outcomes during the settlement process.

Generators will be required to participate in this forward market to qualify for performance credits. This option awards performance credits to those generators that were actually available during the highest reliability risk hours.

E3 estimates that performance credits will compensate resources, on aggregate, $5.7 billion a year — although it also stated that generator revenues would be less stable under this option, unlike under the LSERO or FRM options.

Those facilities that sold credits in the forward performance credit market but failed to perform during the highest reliability risk hours will be penalized, and have to procure performance credits in the retrospective settlement process.

While this option is purported to bring increased reliability at about only a 2% increase in total cost, E3 stated that the PCM option is inherently risky, because it has not been implemented in any electric market in the world to date. E3 estimates it will take two to four years to implement this option.

As noted, one of the repeat criticisms of the report has been that the report and analysis conducted uses a weather sample from 1980 to 2019, and therefore, it does not include in its sample the extreme weather experienced during winter storm Uri. The report assumes that future weather conditions will have the same variability as has occurred over the past 40 years, though ERCOT has seen greater weather variability in the recent past.

E3 stated that additional analysis is needed to incorporate the type of extreme weather experienced during winter storm Uri. This arguably calls into question the reliability benefits and costs of each of the proposals. If market changes are being made in response to winter storm Uri, then it would be reasonable for any analysis on responsive market changes to model for and analyze those changes under winter storm Uri conditions.

In addition, the report assumes certain facts about the planned resource additions and retirements between 2022 and 2026, assuming resource additions totaling nearly 40,000 megawatts of solar, wind and energy storage, based on ERCOT's May Capacity Demand and Reserve, or CDR, report.

This use of the CDR, without modification, is in spite of the CDR being widely criticized in the past for being inaccurate — with ERCOT even disclaiming the accuracy of the CDR within the report.[2]

Additionally, the report assumes growth in ERCOT demand of 20% — i.e., 77 terawatt-hours — by 2026. The report also assumes that generators will have unlimited access to fuel, which may not be an appropriate assumption in an extreme winter event or during times of fuel shortage.

While the report was recently issued, there are already complaints as to the costs of each option, with fear being expressed that any of these options will increase the cost to consumers who are already experiencing high energy costs.

In addition, each of the report's options have been criticized by various constituents. The LSERO option could present a risk of allowing generators to exercise market power, as well as causing challenges to address cost shifts related to load migration that would occur after the close of the forward compliance period.

E3 notes that the FRM option would address these concerns, through an ex post allocation of reliability costs among load serving entities based on actual consumption during the critical hours, and through the ability of the independent market monitor to mitigate generator bids into the centrally cleared market.

The report found the DEC option provides few incentives for real-time performance during the high-risk hours, limited competition among resource types, and little ability to address risk related to extreme weather events. Because the PCM option is assessed each year based on actual conditions, it has been criticized as being unable to reflect infrequent extreme weather conditions, and thus may not reflect any extreme weather.

Additionally, the PCM option is seen as overly complex, and the time it would take to implement such a novel new option and the cost of implementation is truly unknown. While it is predicted the PCM option may take up to four years to implement, because it has never been implemented before, it is easy to imagine implementation taking longer.

Given the huge stakes at hand, and the countless Texan lives that could be put at risk with the wrong choice, many are skeptical that a novel option is the right choice. Texas consumers would be paying for an untested system, on top of what they are already paying for electricity.

While the BRS option would result in the smallest change to the current ERCOT market framework, and has the shortest implementation timeline, E3 noted that the option results in scarcity pricing occurring when there is no true scarcity on the system, and may not be consistent with competitive market principles, since it holds generation out of market while market participants are unable to avoid BRS costs through their own decisions related to resource procurement.

Yet another criticism of the report is that it was conducted by E3 — which was previously retained by two generators with a gas portfolio to provide independent analysis of ERCOT market design and recommend reforms to the PUCT.[3]

While E3 has claimed they would take an independent and neutral approach to their review of potential market designs, it may be difficult to convince the public that E3 began their study with neutral assumptions — especially when the proposals offered will benefit the same type of generators that originally engaged them.

None of the options presented in the report appear to rectify the issues seen during winter storm Uri. There is no stopgap proposed to suspend prices during an emergency when demand exceeds supply, which is something that has been widely criticized after winter storm Uri.

There is also no proposal for how to better respond in a similar winter emergency situation; instead, the solutions offered will merely raise prices for Texas customers, with only the possibility that it may prevent another disaster. Houston Daily reported that the executive director of Energy Alliance, Bill Peacock, stated that the costs to Texas customers could reach "$6.4 billion a year above the market price."[4]

It is possible that all the options in the report may be suboptimal, given that the report did not study the events that unfolded during winter storm Uri. Prior to winter storm Uri, it was believed Texas had a market that would result in a one-day-in-10-year, or 0.1 day per year, loss of load expectation.

Yet winter storm Uri happened — and produced disastrous results. The options given by E3 in the report provide, at best, the same loss of load expectation predicted before winter storm Uri — so one must question if these solutions offer anything closer to reality than what was assumed about the system two years ago.

Since the outcomes of all of these options depend upon incentivizing new generation investment, market certainty is critical to all of them. While ERCOT market reform is up in the air, however, it is hard to image that investment in the state will not be adversely affected by the uncertainty.

On Nov. 10, the PUCT held an open meeting where the commissioners discussed the report. While the report and E3 recommended implementing the FRM option, PUC staff expressed their support for the PCM option, calling it a hybrid approach with elements similar to the LSERO option.

PUC staff further stated that based on their review, the PCM design fulfills the requirements set out by Texas S.B. 3, which was enacted in response to winter storm Uri. During the open meeting, Chairman Peter Lake expressed his support for the PCM recommendation, stating that ERCOT should not rely on a crisis-based business model.

Lake asserted that the PCM option is a way for customers to pay for what ERCOT needs when they really need it, unlike a capacity market, and would move the risk to private resources and not ERCOT. Commissioner Lori Cobos expressed support for a near-term solution, stating that BRS could be implemented the fastest. While each commissioner expressed a preference for a specific design option, all agreed to keep an open mind during ongoing discussions.

The PUCT has requested comments on specified questions related to the report. These comments are due by noon on Dec. 15, and are limited to 25 pages, to be filed in PUCT Project No. 54335, Review of Market Reform Assessment Produced by Energy and Environmental Economics Inc.

The questions primarily focus on the PCM recommendation, as that recommendation was not part of the PUCT's previous discussions related to ERCOT market reform, so stakeholders have not previously had an opportunity to comment on the recommendation. The objective of the PUCT appears to be to adopt a final solution by January 2023, in order to allow state lawmakers to weigh in during the legislative session if they so choose.

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should not be taken as legal advice.

[1] See PUCT Project No. 52373, Review of Wholesale Market Design, PUCT Memorandum at 1 (Nov. 10, 2022), https://interchange.puc.texas.gov/Documents/52373_382_1251440.PDF.

[2] See May 2022 CDR.

[3] E3 and Beth Garza Comments on the Oct. 26, 2021, Questions for Comment, PUC Project No. 52373, Review of Wholesale Electric Market Design (Nov. 1, 2021), https://interchange.puc.texas.gov/Documents/52373_219_1164308.PDF.

[4] Peacock: Market designs recommended in PUC/E3 report will cost Texas billions, Houston Daily (Nov. 21, 2022), https://houstondaily.com/stories/635275136-peacock-market-designs-recommended-in-puc-e3-report-will-cost-texans-billions.