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

COMMENTS OF ENCHANTED ROCK LLC RE: E3 MARKET REFORM ASSESSMENT

TO THE HONORABLE PUBLIC UTILITY COMMISSION OF TEXAS:

Enchanted Rock LLC ("Enchanted Rock") appreciates the opportunity to provide these comments in response to the Public Utility Commission of Texas ("Commission") report ("Report"), "Assessment of Market Reform Options to Enhance Reliability of the ERCOT System," produced by Energy and Environmental Economics, Inc. ("E3")

I. INTRODUCTION

Enchanted Rock supports the Commission's goals of promoting the supply of dispatchable generation and improving long-term energy reliability through ERCOT market reform. Indeed, over the past several years, Enchanted Rock has added 569 MWs of dispatchable, diesel or gas-fired distributed generation. With over 166 MWs of our gas-fired generation under development, we are expanding at a growing pace, even while transmission level gas generation development has slowed over the same time. Enchanted Rock remains active at ERCOT, the Commission, and the legislature to advocate for reforms that value needed reliability, i.e., fast-starting, long-duration, local resilient generation capacity.

As an overarching principle, the Commission should consider distributed energy resources ("DERs"), like Enchanted Rock's natural gas reciprocating engines, as an integral part of the state's energy strategy. Active participation by long-duration, dispatchable distributed resources will improve competition and efficiency of supply in any market design and lower costs for consumers. Additionally, these assets bring resiliency value to local communities and the grid by being sited at customer loads, ensuring the continuous operation of critical services through widespread or localized grid outages and while traditional generation is experiencing high forced outage rates. Full participation from DERs will require that the ultimate market design not be strictly limited to resources that are dispatched by ERCOT's market software, as many DERs operate as settlement-only generators to better manage their dual roles for on-site resilience and grid services. We also note the criticality of various ongoing efforts to lower interconnection and market participation barriers to entry for DERs.[1]

From a cost effectiveness perspective, DERs can provide greater value than the status quo strategies under the current market design. For example, diesel generators are a low-cost solution for backup power. However, their air permit and fuel storage limitations make it infeasible to provide grid services and generate offsetting market revenues. Meanwhile, the marginal resource that is assumed in the market design analysis, the aeroderivative combustion turbine, will require large market revenues to provide needed dispatchable, peaking services to the grid. The deployment of long-duration, dispatchable DERs allows the resiliency and grid services needs to be met with a single asset, resulting in lower costs for the market procurement of reliability services and resiliency for critical facilities and community services.

Whatever policy direction the state decides to take, the Commission should give careful consideration to maximizing the effectiveness and economic efficiency of a new market design by facilitating robust DER participation.

II. RESPONSES TO SELECT QUESTIONS

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

[1] This includes the reform of ERCOT Protocol 3.8.6 relating to DER interconnection on curtailable circuits, Project 54233 on Interconnection Processes, and 53911 on Aggregated DERs.

The lack of precedent for implementation does present a challenge for the PCM's successful, near-term operation in the ERCOT market. Without a track record of performance in other markets, there is significant risk that the PCM's initial implementation *ex nihilo* results in suboptimal results and unintended consequences. Given the development timeline for large generation projects of four to six years, it could take the better part of a decade to develop a PCM that is tuned and well-tailored to the state's needs. Texas may not be able to afford the long ramp-up time for an effective PCM, given the current and forecasted need for more dispatchable, long-duration generation capacity to help manage the intermittency of rapidly growing renewable resources and to provide resiliency for the system during energy emergencies.

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?

Relative to a design like the Forward Reliability Market, the PCM provides far less price certainty for generation developers and, due to a lack of resource accreditation, less control for the Commission and ERCOT over how reliability attributes are being valued. That said, the PCM's ability to achieve its intended goals will be highly dependent on the implementation details, as discussed in the responses below.

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 was passed in response to the tragedy of Winter Storm Uri with the intent to address system shortfalls that arose during those emergency conditions. In selecting a reliability standard and market design construct, the Commission should consider how the overall strategy provides value for desired performance attributes to address emergency situations—duration capability, start times, ramp rates, and proximity to load, i.e., ability to mitigate delivery risk associated with transmission or distribution constraints or outages due to extreme events.

Specifically, Enchanted Rock supports market design standards or criteria that would provide a premium to resources that can start up, parallel and ramp to full output within 10 minutes and operate continuously for extended periods (e.g., >24 hours). It is difficult to evaluate the PCM proposal in this respect because the E3 report does not consider how the market design would operate in an extreme weather scenario like Winter Storm Uri.

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?

The proposed method for evaluating the periods of highest reliability risk may not be effective in representing true scarcity hours and will be extremely difficult to predict.

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?

No response.

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

As proposed, PCM revenues would not necessarily flow to those resources that are most available or that have the most valuable reliability and resilience attributes. Instead, revenues will flow to those resources that have the best forecasting and that find a measure of luck in managing the potential peak hours for retroactive settlement.

Additionally, valuable behind-the-meter ("BTM") resources and demand response will not be incentivized appropriately because, as proposed, they are required to dispatch to generate performance credits, while traditional generation is only required to be available via energy & ancillary service offers. As a result, highly reliable resources that can respond in minutes may end up uncompensated while slower, less reliable resources collect performance credits solely based on their offer behavior.

Take for example a customer that has invested in dispatchable BTM generation. In the event there is no shortage in the market, the BTM generation has no reason to dispatch and no way to predict the retroactive settlement hours in the PCM. As a result, the customer will have to pay PCM for the full load to support other resources, when they have on-site dispatchable capacity that can cover their full needs in an emergency. It would be reasonable to provide credit to these types of resources based on availability, e.g., cleared Emergency Response Service (ERS) resources should be eligible to generate performance credits for availability during their contract periods.

The discrepancy between generation and demand response participation needs to be addressed in implementation.

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

No response.

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?

Yes, given the long lead time required to develop a major market redesign and for new bulk power resources to enter, the Commission should consider deploying a bridge product to incentivize near-term response. New resources like Enchanted Rock's distributed gas generation can be deployed rapidly—operational in approximately 50 weeks from when a purchase order or Notice To Proceed is finalized—in response to a bridge program incentive or price signal. As the Commission looks ahead to incoming load growth, a bridge program can help incentivize large loads to deploy DERs, reducing strain on the grid and supporting ongoing economic development and growth in the state. For example, a 60 MW Microsoft data center in CA will be able to operate with confidence despite statewide capacity deficits and provide load relief by deploying Enchanted Rock's generation thanks to a robust price signal provided by the state's demand response programs.[2]

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, a bridge solution should still be considered, even if the ultimate solution is delayed. A design as ambitious as the PCM should not be rushed, and near-term needs can be met with an incremental program like BRS. Procurement of additional Ancillary Services on a long-term commitment would not be sufficient because current Ancillary Services do not effectively direct revenues to the resources that provide the most reliability and resiliency value, i.e., fast starting, long duration, fast ramping.

Specifically, ERCOT Protocol 3.8.6 does not allow full Ancillary Services participation by DERs due to ERCOT concerns about non-performance risk during utility load shed activities, meaning the resources that are best positioned to respond quickly to such a bridge program could not access the program. This limitation on DERs is unwarranted. The risk of individual feeder outages due to load shed events, even in a supply shortage scenario, is very low. The rule does not appropriately consider the reliability and resiliency value of having DER aggregations that are not subject to the single contingency risk that large generators face. Rather, the impact to the grid from the loss of an individual DER is muted by the distributed, aggregate performance of DERs on the system.[3] Furthermore, while these DERs are disconnected from the grid they are

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[2] Enchanted Rock to Develop California's Largest Renewable Microgrid to Ensure Resiliency of Microsoft Data Center - Enchanted Rock

[3] See Enchanted Rock's Comments in 51603. <51603_12_1215251.PDF (texas.gov)>

"The Commission should consider a scenario where a geographically diverse portfolio of 100 MW of DGRs is participating in the ERCOT market to provide reliability services. In the event of a severe load shed event, the portfolio of DGRs may face the loss of 20-30% of its resources to load shed. However, since most of these DGRs are likely to provide their response as a mix of load reduction and export capacity via behind-the-meter generation, the actual impact to the system is not a 20-30% loss of DGR capacity, but something closer to 4-6% of the DGR capacity (assuming that only 20% of the 20-30% curtailment capacity represents the export capacity of the DERs) since the committed load reductions will have been achieved in full through load shedding. Meanwhile, bulk power still providing power to the customer, albeit in islanded mode, which is the ultimate goal of the Commission. As part of the bridge program effort, the Commission should ensure that this unreasonable barrier to DER participation is removed. This would be consistent with the Commission's analogous intent to allow transmission-connected resources to continue generating performance credits even if they were curtailed due to transmission-related issues, as noted at the December 2 E3 Market Design Technical Presentation.

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

With regard to any future market design construct, robust DER participation will result in greater competition and efficiency in the market, reducing adverse impacts to consumers. Similarly, the cost of consumer resiliency is positively impacted if the market value of such DERs is recognized on par with traditional generators for their performance attributes of availability, response time, and operating flexibility.

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.

The Commission should look to build on existing programs and market design ideas that have worked to incentivize the deployment of dispatchable, near-term resources. If there are concerns about BRS, a variation on the Emergency Response Service could be developed. Such a program might operate with its own budget, qualifying resources based on a clear set of verified performance requirements on duration, ramp rates, and quick start abilities and providing compensation based on a fixed incentive level for a five-year to ten-year commitment.

12. In what ways could the Dispatchable Energy Credit design be modified through quantity and

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system generation is likely to be experiencing forced outage rates in the 30-40% range for the grid to require load shedding in the first place. The Commission should prioritize near-term review and reform of ERCOT's DGR model to remove this undue barrier to full market integration of DERs."

resource eligibility requirements, e.g., new technology such as small modular nuclear reactors, in such a way that it incentivizes new and dispatchable generation?

The Dispatchable Energy Credit ("DEC") design, because it relies on compensation for MWhs produced, fundamentally favors resources that have high capacity factors. High capacity factors have no benefit to the grid when the system needs dispatchability. While resource eligibility criteria could be adjusted to ensure DEC resources also provide certain reliability and resiliency value, e.g., ramp rate, duration, and availability, it is still limiting with respect to capable technologies that are not intended for baseload service. Such criteria would not solve the problem of distorting markets by incentivizing dispatchable resources to engage in behavior to maximize MWhs.

Thank you for your consideration.

Best Regards,

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EXECUTIVE SUMMARY OF ENCHANTED ROCK COMMENTS

- The Commission should consider DERs, like Enchanted Rock's natural gas reciprocating engines, an integral part of the state's energy strategy.
- Robust participation by distributed resources in the PCM, or any market design alternative, will improve competition and efficiency and lower costs for consumers.
- Full participation from DERs will require that the ultimate market design not be strictly limited to resources that are dispatched by ERCOT's market software, as many DERs operate as settlement-only generators to better manage their dual roles for on-site resilience and grid services.
- The Commission should continue to press for removal of undue barriers to DER participation, such as the ERCOT Protocol 3.8.6 requirements requiring interconnection via non-curtailable circuits.
- Market rules should appropriately consider the reliability and resiliency value of aggregations of DERs.
- Enchanted Rock supports market design standards or criteria that would provide a premium to resources that can start up and carry load within 10 minutes and operate continuously for extended periods (>24 hours).
- Commission should consider deploying a bridge product, even if the ultimate solution is delayed, to incentivize large loads to deploy DERs to reduce strain on the grid and support ongoing economic development and growth in the state.