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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**

COMMENTS OF
TEXAS ELECTRIC COOPERATIVES, INC.

Texas Electric Cooperatives, Inc. (TEC) respectfully submits these comments in response to the Public Utility Commission of Texas (Commission) Staff's (Staff) questions regarding the *Assessment of Market Reform Options to Enhance Reliability of the ERCOT System* report (E3 Report).[1] TEC is the statewide association of electric cooperatives operating in Texas, representing its members except as their interests may be separately represented.[2] The request for comments directs responses to be filed by December 15, 2022. These comments are timely filed.

I. Responses to Staff Questions

1. The E3 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, TEC believes that the Performance Credit Mechanism (PCM) does face implementation hurdles due to its novelty. The E3 Report indicates that the PCM could take up to four years to be implemented, two years minimum.[3] TEC is not critical of the PCM simply because it is new. ERCOT's initial adoption of its Nodal Protocols was a controversial and relatively novel project when the protocols were submitted for Commission approval and adopted in 2005.[4] The Nodal Protocols were even appealed to state court.[5] As shown through implementation of ERCOT's Nodal Protocols, even a controversial novel concept can be accepted over time. A novel concept is not necessarily a bad one, but it does create additional difficulties in implementation, requiring proper ERCOT system build outs and studying of data to ensure the PCM works as

[1] Project No. 54335, *E3 Report, Staff Memo and Updated Questions* (Nov. 10, 2022) (E3 Report).
[2] TEC's 75 members include distribution cooperatives that provide retail electric utility service to approximately 5,000,000 consumers in statutorily authorized service areas that encompass more than half of the total area of the state. TEC's G&T members generally acquire generation resources and power supply for their member distribution cooperatives and deliver electricity to them at wholesale.
[3] E3 Report at 82.
[4] *Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to Subst. R. §25.501*, Project No. 31540, Order (Apr. 5, 2006).
[5] *Id.*, Letter Requesting Representation by the Attorney General - Cause No. D-1-GN-06-002131 (Jun. 14, 2006).

conceived. For example, a preliminary demand curve for Performance Credits (PCs) could initially be developed in a relatively short period of time based on historical observations. However, given the different behavioral decisions relating to outage scheduling and commitment induced by the mechanism and its interaction with energy and Ancillary Services revenues, it would take additional time and modifications to develop an accurate demand curve. This process would require observation and data collection under the new system to finalize. ERCOT and the Commission will necessarily need to observe multiple annual usage cycles to determine and/or refine an appropriate demand curve that accurately produces the reliability enhancements expected of the PCM in the ERCOT market.

Similarly, the PCM also relies on determining a set of critical hours for the payment of PCs to generators and the allocation of costs to Load Serving Entities (LSEs). It was mentioned during a hearing of the Senate Committee on Business and Commerce that the number of hours may be changed from thirty as outlined by E3 to four per month for a total of forty-eight per year.[6] TEC is concerned that the set of critical hours (and when those hours are likely to occur) may be subject to ongoing revision, and uncertainty around the number of critical hours used to determine how generators are paid and loads are charged will take a number of years to finalize after the PCM is implemented. By analogy, currently under the four coincident peak (4CP) transmission cost allocation method, cooperatives and other providers are able to control their costs and minimize their impact on the electric grid by working to minimize their consumption during the coincident peaks. Tracking and responding to an additional to-be-determined subset of critical hours throughout the year will require trial and error that could yield unintended volatility in prices. Cooperatives and other providers will need to establish new processes to manage their costs and impacts on resource adequacy, and generators will likely adjust their behavior in response to the new incentives.

Additionally, TEC is concerned that tracking a set of critical hours on an annual basis could, in some years, yield a concentration of hours in the summer months when ERCOT usually experiences its highest load. However, ERCOT's periods of highest load do not necessarily coincide with the grid's greatest times of need. TEC believes it may be more appropriate to observe critical hours on a seasonal basis in order to gain a more thorough view into annual fluctuations

[6] Hearing of the Senate Committee on Business and Commerce at 2:59:30 (Nov. 17, 2022).

and needs of the ERCOT grid relative to the power available at any given time. As an example, a shoulder month like April does not typically see record load on the ERCOT system. However, due to the expectation of more moderate load in these months, it is common for generators to take their assets offline for maintenance, which may in fact lead to greater scarcity issues in an otherwise low-load month. Because the PCM bases the credits awarded on the previous year's performance, an annual allocation following a year with a hot summer could result in a heavy concentration of hours in the summer months and may miss the times of greatest need that occur in the shoulder months.

Due to the novelty of the PCM and the use of a retrospective application of credits and charges, the PCM may not entirely alleviate uncertainty in the capital markets. Until the methodologies and practices are proven and certain key details finalized, as described above, it may be difficult to induce investment in large-scale dispatchable generation in ERCOT through the PCM. For entities like co-ops, financing future projects in the early years of the PCM may come with additional costs due to the relative uncertainty until the PCM is more widely accepted as a viable format.

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 intention of the PCM is to incentivize performance by inducing generator participation and LSE conservation at the times of greatest need, in theory.[7] However, it is uncertain whether this design will incentivize new generation or retention of older generation, and its impact on performance is similarly questionable.

New construction and retention of older units will remain a decision based on profit or loss. Building new generation or paying maintenance on older units is a costly endeavor. It is unclear whether the PCM design will directly incentivize any retention or new build decisions due to uncertainty around the effectiveness and durability of the PCM design and the corresponding large costs associated with capital investment in utility-scale generation.

[7] E3 Report at 21 – 25.

Retention of older units in particular may not be affected by the PCM. The PCM relies on reliability payments based on actual performance through offers into the market.[8] If an older unit is unable to offer into the market during critical hours due to maintenance issues or longer required start times, the older unit will not benefit from the PCM. Therefore, no incentive will exist, and the owner or operator may in fact be incentivized to more rapidly retire older plants that are not able to take advantage of the PCM relative to the competition.

The PCM's provision of credits may incentivize some minor efficiencies or upgrades on a small scale to allow existing generation to take greater advantage of the performance credits. The cost of major upgrades or maintenance that would extend the life of an older unit could outweigh any PCM benefit. Similarly, the cost of new construction is unlikely to be justified solely by the PCM, but the actual impact is unknown and depends on many unresolved details. The PCM may figure into the overall cost/benefit calculus of whether to extend an old unit or build a new unit but is unlikely to be the basis for a decision to retain or build on its own.

With regard to performance, TEC notes that the intent of the PCM is to support performance by incenting units to be available during certain hours. However, TEC is cautious because this may also create unintended consequences regarding planned resource maintenance. Generation owners may delay necessary maintenance or down time for a plant in order to maximize performance credits, possibly creating compounding reliability issues if plants experience increased wear and tear and forgo or delay needed repairs and upgrades. Further, as discussed below, the PCM will induce generators to be available in certain hours that may not correspond to the best use of the generator or the time of greatest system need.

The PCM, due to its incentives for performance during certain critical hours, is designed in theory to support performance during times of net peak load. However, it is less clear if PCM would support any change in performance during extreme weather. The PCM does not consider the ability of a unit to operate during a prolonged extreme weather event. Rather, the PCM is based entirely on performance during hours of low operating reserves, which may not occur during weather extremes, and the PCM is not designed to account for or reward generators with resiliency attributes that support performance during these prolonged events.

[8] *Id.* at 21 – 22.

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)?

TEC believes that one or more reliability standards should be considered and implemented in ERCOT, resulting in the right type and quantity of reserves that is at least as conservative as the reserve standards applied in other domestic markets. The 1-in-10 Loss of Load Expectation (LOLE) is the primary standard used in other markets at this time and currently forms the basis for the minimum ERCOT planning reserve margin criterion (set by the ERCOT Board of Directors at 13.75% in 2010).[9] TEC understands that the Southwest Power Pool (SPP) is evaluating changes to its reliability standard to incorporate additional dimensions beyond installed capacity – this inquiry may inform the reliability standard the Commission applies in ERCOT. TEC recognizes that the Commission is evaluating a number of metrics and agrees this is a prudent approach to better maintain system reliability. Again, TEC suggests that ERCOT use these metrics to maintain reserves for ERCOT that are as least as high as the reliability standards set for other domestic markets.

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?

As discussed above, TEC is concerned that analyzing the thirty highest hours of reliability risk on an annual basis may create complexity that is difficult for market participants to manage and may not address instances of greatest system stress. At a recent legislative hearing, Chairman Lake mentioned the possibility of changing the design to instead target four critical hours per month.[10] Cooperatives and other load serving entities endeavor to control costs for their consumers by planning around coincident peak hours that occur four times per year and dictate the allocation of system-wide transmission costs. Under the PCM construct, LSEs such as co-ops will have to account for a new paradigm of cost allocation based on a to-be-determined critical period that will not likely align with 4CP. This level of planning will be challenging for some TEC members because these hours will be difficult if not impossible to predict. Cooperatives and other LSEs will

[9] ERCOT Nodal Protocols Section 3.2.6.1 and *ERCOT Target Reserve Margin Study* at 17 (Nov. 1, 2010).
[10] Hearing of the Senate Committee on Business and Commerce at 2:59:30 (Nov. 17, 2022).

struggle with developing this insight because the E3 Report ties the hours to those with lowest marginal operating reserves, which can occur on mild or moderate days and will be affected by unpredictable factors like generator outages, ERCOT out-of-market actions, and the behavior of other market participants. TEC is not aware of any tools or forecasts available to assist with managing this type of cost allocation or payment system.

Additionally, in certain years there may be very little actual concern during a subset of these hours – the system may not experience anything close to an emergency. The construct could create circumstances where cooperatives change their behavior to target hours that do not reflect true system need. Cooperatives attempting to reduce consumption during those hours will likely be unsuccessful in some cases and will target hours that do not end up being critical hours as defined by the PCM. Cooperative member-owners may experience demand response fatigue as the LSE repeatedly asks them for conservation to try to manage the end users' costs. The PCM introduces extensive complexity that in practice may not be manageable and may not result in improved reliability. It is further unclear if the PCM would address or alleviate the disruptive impacts of ERCOT's current reliance on the Reliability Unit Commitment (RUC) mechanism.

TEC recommends ERCOT and the Commission first explicitly define what is considered a critical hour and review recent years to assist the market with understanding how the construct would have functioned in terms of cost allocation and the award of PCs in prior years. In review of prior years, ERCOT could identify which hours actually represented a reliability risk and develop a metric based on that analysis, rather than a more arbitrary predetermined set of hours that does not appear to be tied to system conditions or operational experience. Further, it would also be beneficial for ERCOT to consider trends related to the additional interconnection of intermittent and limited duration resources and how these trends may affect when critical hours are likely to occur. As explained in further detail below, TEC recommends that ERCOT and the Commission consider reviewing a smaller number of critical hours on a seasonal basis to capture the unique needs of the ERCOT system as it transitions from moderate load in the shoulder months to peak load in the summer and winter months.

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?

TEC believes it would be more appropriate to look at seasonal critical hours in order to avoid a near-total concentration in summer that could occur in certain years with an annual determination. While TEC believes seasonal allocation could be appropriate, a monthly determination would likely increase the chances that the critical hours do not actually occur during times of true system stress. Although critical hours could occur during any month, they are likely clustered around summer, winter, and certain shoulder months. Critical hours have a more seasonal character than a monthly one, and the Commission should not arbitrarily assign hours as critical just to meet a quota of four per month. ERCOT should produce historical analysis to assist the Commission with the determination of the critical period and consider how the interconnection of additional intermittent and limited duration resources will affect that period.

Further, the Commission should consider circumstances of critical system need that may not align with periods of low reserves. Winter Storm Uri is an example of such an event. Even under load shed conditions during Winter Storm Uri, certain hours may not have qualified as critical hours under the PCM, because ERCOT was accumulating high levels of reserves. TEC posits that this outcome should be taken into consideration in the development of the period of highest reliability risk.

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?

According to the E3 Report, a voluntary forward market for generator offers and a mandatory residual market would incentivize resource availability.[11] However, TEC believes more information is needed on the purpose of the forward market for LSEs and generators. LSEs already have options to hedge their costs, and it is not apparent to TEC that this design increases transparency. TEC believes more discussion is needed regarding the purpose and impact of the voluntary forward market.

[11] E3 Report at 84 – 85.

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

TEC takes no position and believes this question may be more appropriately directed at the Independent Market Monitor.

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?

TEC does not currently see a compelling need for a "bridge" product or service, given the time and cost associated with developing such a product. For example, attempting to implement the BRS as a temporary solution would entail costs, potential rulemakings, and take significant time to implement, up to three years for full implementation according to E3.[12] This is likely too much of a hurdle from a timing and cost perspective for BRS to act as an interim solution while more holistic solutions are developed.

To the extent the Commission believes a bridge product is required to maintain system reliability, TEC suggests ERCOT may be able to implement a product similar to the existing Reliability Must Run (RMR) service. Under RMR, the Commission has the ability to retain resources that otherwise would exit the market. There may be an opportunity to temporarily adjust the RMR service to target the LOLE of 1-in-10 or the Commission's desired reliability standard(s). Using the existing RMR process to act as a bridge to retain resources E3 believes will otherwise retire[13] could pose less of a challenge from a timing or cost standpoint in comparison to attempting to implement the BRS on an interim basis.

TEC understands that RMR was designed for and is more generally used to address a transmission issue and not a system capacity issue. Accordingly, applying RMR for system capacity is problematic and antithetical to the current ERCOT market design. TEC therefore does not endorse RMR as a long-term solution, but notes that RMR may be an option if the Commission determines it must have a bridge mechanism to prevent market exit.

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[12] *Id.* at 82.
[13] 11,560 MW expected to retire per E3 Report at 46.

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?

TEC notes that 5,630 MW is not an actual deficit occurring on the system, but an outcome expected according to the simulation conducted by E3 that is contingent on multiple assumptions. Rather than attempting to secure that specific amount of generation, TEC recommends that ERCOT and the Commission look to the dynamic needs of the grid, not just the 5,630 MW believed necessary for the 1-in-10 LOLE standard according to a theoretical model.

Use of a bridge product, since intended to be temporary, should be cost effective, relatively easy to implement, and come with a knowledge that its use is temporary in nature. As stated previously, the Commission and ERCOT should study the use of a product based on a currently existing service, such as RMR, to serve as a bridge to the ultimate solution. Use of a current service is preferred from a cost-effectiveness standpoint, likely could be implemented easily, and would allow the Commission to set an expiration date in consideration of when the ultimate solution adopted by the Commission goes into effect. As noted above, as a general matter TEC does not endorse RMR. However, the use of RMR or a similar equivalent to address the transition period prior to the implementation of Phase II may be appropriate, in consideration of the alternatives.

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

E3 estimates the cost of PCM to be $460 million annually.[14] This cost figure represents a long-run equilibrium outcome that will fluctuate on a year-over-year basis. In particular, if the assumptions applied in the construct identify a capacity shortage, the costs may be much higher. Conversely, costs would decrease in a system with excess capacity. The estimated costs are highly dependent on the assumptions used in the model and in practice will hinge on many unresolved elements of the design, including the demand curve for PCs and the reliability standard. Further, the PCM, as TEC understands it, is not designed solely to reward dispatchable generation but applies to any generation source that is available during the critical hours.[15] If the PCM is only

[14] *Id.* at 60.
[15] Hearing of the Senate Committee on Business and Commerce at 1:26:00 (Nov. 17, 2022).

applied to dispatchable generation, as mandated by Senate Bill 3,[16] the costs of the construct would be reduced. Chairman Lake testified that the PCM costs, if focused on dispatchable generation, could be reduced over the long term.[17]

TEC additionally emphasizes that the costs of the PCM should be distributed in a fair manner, and no particular class of customer should be advantaged. For example, certain industrial consumers are able to respond to prices in real time and have developed tools to respond to high-demand days to avoid the allocation of transmission costs during the 4CP intervals. In contrast, residential consumers are generally not as responsive to price signals because there is not an immediate impact or notification of higher prices during peak load. If the costs of PCM are allocated based purely on consumption during critical hours, TEC is concerned that costs for the PCM, while benefitting the whole of the ERCOT market, may disproportionately impact residential consumers.

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 fastest design and implementation of a bridge would be to use a product based on an existing service such as RMR, as described above.

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?

DEC is the costliest and least efficient design, according to E3,[18] so it is unlikely to be effectively modified in such a way as to incentivize new dispatchable generation, even with a shift in eligibility requirements.

[16] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001 – 66.016 (PURA) § 39.159(c)(1).
[17] Hearing of the Senate Committee on Business and Commerce at 1:26:00 (Nov. 17, 2022).
[18] E3 Report at 76. *See also Id.* at 55.

II. Conclusion

TEC appreciates the opportunity to provide comment in response to the request of Commission Staff and looks forward to working with Staff and the other stakeholders in this project.

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Respectfully submitted,

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Executive Summary

TEC makes the following observations and recommendations in response to the questions presented:

- The PCM faces numerous implementation concerns due to its novelty, including:
  - Development and refinement of an accurate demand curve;
  - Determination of critical hours; and
  - Potential struggles in attracting capital investment with an untested market structure.

- The PCM is designed to incentivize performance but may have unintended consequences.
  - These incentives may not work to retain older units or bring in new generation.

- The Commission and ERCOT should define "critical hours" and provide a look-back study to show market participants how the PCM model would have worked in previous years to give a road map as to how the model may function going forward.

- The number of critical hours should be reduced and allocated on a seasonal basis.

- TEC recommends using a product based on an existing service like RMR as a bridge to the Commission's preferred solution.

- If the PCM is the chosen model, the PCM should be focused on dispatchable generation and costs allocated in a manner that does not unduly burden certain classes of consumers.