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

CITY OF DENTON dba DENTON MUNICIPAL ELECTRIC'S RESPONSE TO STAFF'S NOVEMBER 10, 2022, QUESTIONS FOR COMMENT

The City of Denton through its Municipally Owned Utility (MOU) Denton Municipal Electric (DME) appreciates the opportunity to respond to the questions for comment proposed by the Public Utility Commission of Texas (PUCT) related to the Energy and Environmental Economics (E3) report titled "Assessment of Market Reform Options to Enhance Reliability of the ERCOT System".

DME provides electric service to over 60,000 meters in Denton, Texas and is a Non-Opt In Entity (NOIE) under Section 16.3 of the ERCOT protocols. DME operates five (5) Qualified Scheduling Entities (QSEs). DME's power supply portfolio includes over 500 MW of renewable energy resources, the 225 MW Denton Energy Center (DEC) a natural gas internal combustion plant and provides QSE services for a 300 MW Controllable Load Resource (CLR).

DME's responses to the questions posed by the PUCT are intended to make clear that the directive of the Legislature to the PUCT in Senate Bill 3 (SB3) are actionable by any Phase 2 market design that the PUCT votes upon. We believe that the phase 2 market design must:

1. result in the construction of new dispatchable generation in a timely manner to address the impending build out of solar and wind generation that will significantly increase load

shed risk in the absence of new dispatchable generation coupled with meaningful demand response;

2. achieve an acceptable level of load shed risk at the lowest possible cost; and
3. maintain the competitive energy market that has enabled Texas to attract economic development and to ensure a high standard of living.

DME questions whether any of the evaluated market designs in the E3 report meet the entirety of the requirements of SB3. As an example, the requirement to "establish ancillary services in a manner consistent with cost-causation principles and on a non-discriminatory basis"[1]. DME's analysis of the Performance Credits Mechanism (PCM) places much of the cost on Load Serving Entities (LSEs) who rely on intermittent renewable energy to serve but fails to value the low cost, clean energy that is available to the entire ERCOT market during most hours of the year. As proposed, these intermittent resources will not be able to participate in the voluntary centrally-cleared Performance Credit (PC) market because they can't guarantee that they will be generating during the compliance period. That inability to participate, without great financial risk, nullifies their ability to provide PCs in the retroactive settlement despite the potential that they could be contributing valuable energy during the compliance period. Consequently, the benefits of the value of their low cost and clean attributes are given no value in the proposed PCM except for their ability to collect energy revenues in the day-ahead and real time market. DME's portfolio of renewable energy capacity is significantly larger than the load it serves and despite the fact that DME owns and operates quick starting, efficient natural gas generation to back up these renewables, as proposed, DME customers will likely be price takers in the retroactive settlement for PCs. At the same time the value of the surplus renewable energy that DME sells to ERCOT, which directly influences the forward price curve, will enable Retail Energy Provider (REP) and their customers to benefit in the form of lower retail prices. As many

[1] SB3 Section 14 (h)

REPs are affiliated with Generation companies, In a way, this is a of surplus renewable energy sold to ERCOT by DME through lower retail rates.

DME supports the Coalition for Dispatchable Reliability Reserve Service proposal[2]as first step in achieving the objectives of SB3. However, even that proposal does not guarantee that new dispatchable generation will constructed in a timely manner. Consequently, DME provides specific recommendations to immediately get dispatchable generation into the market in answer to question 8 herein.

DME believes that the Coalition for Dispatchable Reliability Reserve Service proposal is a much more cost-effective way to achieve resilience and reliability than the current phase 1 conservative market operation that ERCOT is using because it eliminates the out of market actions currently being used to bolster Physical Responsive Capacity (PRC) is the real-time market. ERCOT's Independent Market Monitor (IMM) reported that ERCOT's phase 1 conservative operations have cost consumers $800 million in additional non-spin reserve charges from August 2021 – July 2022, plus $1.6 billion in additional energy costs associated with changing the Operating Reserve Demand Curve (ORDC) and lowering the maximum cap price from $9,000/MWh to $5,000/MWh for the same time period[3]. This incremental $2.4 billion in the market has not resulted in any new dispatchable generation entering the ERCOT interconnection que. Under the Performance Credit Mechanism (PCM), E3 reports that only $460 million in new money will be available to capacity resources, including generators[4]. **DME is skeptical that the PCM market design that is estimated to provide $460 million in new money to incentivize new dispatchable generation when the $2.4 billion of phase 1 new money has failed to incentivize any new dispatchable generation.**

The combination of the Dispatchable Reliability Reserve Service (DRRS)[5] with a limited mandatory dispatchable resources build out that can be accomplished quickly, will meet the requirements of SB3 and put the ERCOT energy only market on a path to ensure reliable

[2] PUCT project 52373, Review of Market Design by the Coalition for Dispatchable Reliability Reserve Service, December 14, 2022 filing.
[3] *Report to the Texas Senate Committee on Business & Commerce*, Potomac Economics (November 17, 2022)
[4] E3 report page 60.
[5] December 14, 2022 filing in PUCT project 52373. Review of Market Design by the Coalition for Dispatchable Reliability Reserve Service

operations in the face of a wave of new, low cost, clean intermittent resources that will characterize the market for decades to come. DME believes this approach not only accomplishes the objectives of SB3 but does so in the most cost-effective way impacting Texas consumers the least and providing the greatest reliability improvement for the lowest cost.

I. Response to Staff's Questions for Comment

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?*

DME Response: The unique nature of the PCM structure and the fact that there are no operating energy markets with the same structure does not in itself present an obstacle for the ERCOT market. However, the time that will be required to fully flesh out the intricacies of the PCM through PUCT rule making followed by ERCOT protocol development will likely take longer than what ERCOT and the PUCT have reported.[6] Numerous fundamental questions about the mechanics of the voluntary centralized forward market, the method of demonstrating compliance by LSEs and the penalty assessment to LSE's in the retroactive settlement associated with customers that have migrated from one REP to another, etc. must be answered. Given the financial implications of the proposed PCM cost at a reported $5.7 billion per year[7] and the many assumptions made to offset that amount with $5.4 billion per year in market energy and ancillary service costs, a deep and thorough stakeholder effort will be required at both the rulemaking and ERCOT protocol development phases. The potential impact to the Texas economy is too large to short circuit this stakeholder process in DME's opinion. Consequently, DME believes a fully developed PCM set of rules and protocols will not be ready for implementation for 3-4 years. Only after the rules and protocols are set, will price signals validate the need for additional dispatchable generation. DME believes it will take a minimum of 36 months site, permit, finance and construct before the capacity additions can be made under the PCM[8]. Thus the "significant obstacle" is time and DME believes that a less complex approach is appropriate as identified in our response to question 8 combined with the DRRS.

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[6] Testimony of Peter Lake and Pablo Vegas before the Senate Business and Commerce committee (November 17, 2022) and House State Affairs (December 5, 2022)

[7] Assessment of Market Reform Options to Enhance Reliability of the ERCOT System, Energy +Environmental Economics, Nov. 2022 pg.59

[8] Chapter 35, Section 13, Subchapter A, Section 35.004 (g)(2)

DME is concerned that the PCM will be too administratively complex to implement in a timely fashion. In addition to the rule making and protocol development, the software system development required for the voluntary centrally cleared market, the tracking systems for compliance, the retroactive settlement, etc. when combined with the changes and upgrades that have to be made to implement real-time co-optimization and the new Ancillary Service products to manage daily operations is likely too much for ERCOT to take on at one time and do it well. The importance of getting it right is paramount given the far-reaching implications of the market design on the Texas economy and that of communities like Denton.

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?*

   No response

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)?*

   No response

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?*

   No response

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 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?*

   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?*

DME Response: Whatever reliability standard is adopted by the PUCT should dictate the actions, or inactions of the market to achieve the targeted reliability standard. DME does not believe that a bridge product to the PCM is needed only because we do not believe the PUCT should adopt the PCM as it fails to meet what we believe the objectives of SB3 which are:

1) construction of new dispatchable generation in a timely manner to address the impending build out of solar and wind generation that will significantly increase load shed risk in the absence of new dispatchable generation coupled with meaningful demand response.

2) achieve an acceptable level of load shed risk at the lowest possible cost; and

3) maintain the competitive energy market that has enabled Texas to attract economic development and to ensure a high standard of living.

DME believes that, with the exception of the BRS proposal that was evaluated by E3, no market designs under consideration by the PUCT provides the immediate and certain price signal needed to incentivize ERCOT market participants and third-party investors to commit risk capital for fast starting dispatchable generation. Based upon our experience operating a fast-starting peaking units in ERCOT as a hedge against a 100% renewable supply portfolio, we believe that these are types of generation assets needed to enable the market to absorb the inevitable intermittent additions that will occur over the next 3-4 years. While the PCM, FRM and LSERO have the potential to provide such price signals, the time required for the needed stakeholder rule making and protocol development will not provide "adequate incentives for dispatchable generation"[9] as mandated by the Texas Legislature on a timeline that will increase (or maintain) the reliability of the ERCOT grid until the needed price signals are provided to the market. Consequently, DME recommends, consistent with comments previously provided to the PUCT[10], a limited build out of quick starting dispatchable generation capacity as determined by ERCOT using known resource additions (generation, storage, demand side, retirements, etc.). The amount of installed capacity to be procured should be sufficient to achieve the adopted Loss of Load Expectation

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[9] Chapter 35, Section 14, Subchapter A, Section 35.004 (g)(2)

[10] See PUCT Project 52373 https://interchange.puc.texas.gov/search/documents/?controlNumber=52373&itemNumber=191

(LOLE) or other reliability metric deemed acceptable to the PUCT. DME recommends that the PUCT adopt the following approach:

- Task ERCOT to study the needed amount of quick starting peaking generation and the optimal location of such generation resources to achieve the reliability standard adopted by the PUCT). The analysis should use reasonable assumptions for forward natural gas and power prices, take into account the known retirements, the expected peak demand of the ERCOT system, transmission constraints, the known resource additions including demand and storage resources, etc., and be focused on the periods of the year when the reserve margin is expected to be the lowest using stochastic analysis incorporating historical regional weather.
- After determining the capacity needed in each region, ERCOT should solicit proposals from generation developers to build the required capacity and select the lowest evaluated cost. Evaluation criteria should include, but not be limited to, fuel security (ideally dual fuel), demonstrated experience developing and constructing such resources, overall capital cost (including return on investment), forecasted operating and maintenance cost and transmission congestion.
- ERCOT, through the State of Texas, shall provide loan guarantees to the selected developers to enable the lowest possible financing cost. Financing of the projects should be through competitive debt markets leaning on the Texas backed loan guarantee to achieve the lowest cost of debt. Securitization of the loan guarantees will be by the residents and businesses of ERCOT via an administrative charge applicable to all energy ($/kwh) consumed in ERCOT.
- The annual fixed (debt, interest, fixed O&M, return on investment, etc.) and variable costs associated with the operation and maintenance of these new dispatchable generation units should be recovered from all LSEs on a load ratio share (LRS) using the same mechanism as the PUCT uses for allocation of the Transmission Cost of Service. Revenues achieved by these reliability units.
- ERCOT should establish a minimum Predicable Reserve Capacity (PRC) below which these new dispatchable units would be dispatched. To avoid disruptions to the energy only market price formation, when dispatched, these units will be paid their actual costs which will in turn be passed through to the LSEs on a LRS basis. ERCOT will have

ability to dispatch units on a regional basis as they determine prudent to mitigate grid reliability concerns. However, DME recommends that ERCOT also study a case where these reliability units clear in the real-time market and are paid the real-time energy price. Such an arrangement would send price signals to older, less efficient generators to retire and make the business case for additional quick starting, long duration dispatchable generation, more demand resources and energy storage resources. Also, consumers would benefit from the revenues collected by these reliability units to offset the annual fixed and variable operating costs. A long-term shift in the generation mix to achieve a desired level of reliability at the lowest cost that leverages the continued development of low cost, clean renewable generation should be an objective of the PUCT.

- Each new dispatchable generator will be periodically tested and inspected by ERCOT to always ensure their state of readiness.

DME believes that the expeditious development of quick start dispatchable generation backed by loan guarantees coupled with DRRS to mitigate out of market reliability measures and high cost conservative operations will provide the most cost effective means of achieving the mandates of SB3 and achieving the desired reliability objectives of the PUCT and ERCOT. We believe that these two initiatives are considerably less complicated than the PCM and will enable the competitive energy market that makes ERCOT unique and continue to make our market one of the most attractive ones fostering continued high levels of economic development.

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?*

   No response

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

II. Conclusion

The City of Denton appreciates the opportunity to submit these comments. DME looks forward to working with the Commission, its staff, and the stakeholders on these important questions and this broader discussion in the coming months.

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Respectfully,

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EXECUTIVE SUMMARY
CITY OF DENTON dba DENTON MUNICIPAL ELECTRIC'S RESPONSE TO STAFF'S NOVEMBER 10, 2022, QUESTIONS FOR COMMENTS

The City of Denton ("Denton") appreciates the extensive work done by the PUCT staff, ERCOT and E3 on evaluating market designs to address the mandates of Senate Bill 3 and to address the changing resource mix in the ERCOT market. This work and the report by E3 provide a benchmark and limited market design details to enable the dialog that is now occurring between market participants to debate the pros and cons of each market design and importantly, the relative probability that such market designs will achieve one of the main objectives of SB3 to incentivize the new dispatchable generation and increase overall market reliability.

Denton's review of the E3 report and subsequent information provided by E3 in the technical conference along with statements from both PUCT Chair Lake and ERCOT CEO Vegas relative to the Performance Credit Mechanism (PCM) market design results in the following assessment:

1. The PCM will not provide sufficient price signals in a timely manner to warrant investment of risk capital into new dispatchable generation.
2. The PCM fails to follow the cost-causation and non-discriminatory principles mandated by SB3 in that the benefits of intermittent renewable energy resources to all Texans in the form of low-priced energy during the majority of the hours of the year is given no credit despite the potential that they could contribute energy during the lowest reserve margin periods. These intermittent capacity resources will not likely be able to participate in the voluntary centrally-cleared PC Market due to the uncertainty of generation during the compliance hours that are settled in the residual market. Consequently, communities that have committed to high levels of renewable energy as a matter of policy and entered into contracts with intermittent renewable facilities will bear the majority of burden of the market's compliance cost with the PCM mandates.
3. The mechanics of how the PCM, if adopted, will work in a competitive retail market are unknown, will likely be overly complex and un-necessarily induce price and performance risk premiums that will be borne by retail energy customers.
4. Given that $2.4 billion per year of new costs in phase 1(conservative market operations) has not resulted in new dispatchable generation, it seems counter intuitive that $460 million per year from the PCM design will be sufficient to guarantee such investments.

To meet the mandates of SB3 and to cost effectively address the known reliability issues that the ERCOT market currently faces and the inevitable increase in intermittent resources, Denton recommends:

- A combination of additional *Dispatchable Reliability Reserve Service* as filed with the PUCT under project 52373; and
- Construction of natural gas fired, quick starting peaking units, securitized by loan guarantees from the State of Texas as a way to a phase 2 ERCOT market design that fully embraces the energy only concept.

SB 3 is clear in its mandate to construct new dispatchable generation. The PCM does not directly meet that requirement. The number of new peaking units, the location and the capacity should be determined by ERCOT based upon known resources additions (energy, storage and DSM), demand growth and retirements of existing dispatchable generation. This recommendation is consistent with prior comments provided by Denton under PUCT project 52373. ERCOT should determine, through its robust stakeholder process whether these reliability units should participate in the energy only market when dispatched or simply recover their actual operating costs. All LSEs will pay for these reliability units on a load ratio share which will be known well before the energy delivery period enabling continued robust retail electric competition in ERCOT.