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

HUNT ENERGY NETWORK L.L.C. COMMENTS

Hunt Energy Network, L.L.C. (HEN) submits the following comments in response to the Public Utility Commission of Texas (Commission) Staff's request for comment on the Performance Credit Mechanism (PCM) as described in the Energy and Environmental Economics, Inc. (E3) report entitled "Assessment of Market Reform Options to Enhance Reliability of the ERCOT System" dated November 2022 (E3 Report). Staff requests that all comments be filed by noon on December 15, 2022; therefore, these comments are timely filed.

INTRODUCTION

Winter Storm Uri was the most devastating winter event in recent Texas history, with $80 - $130 billion in economic damage and at least 210 lives lost.[1] While the Legislature and the Commission have taken firm steps to address many of the contributing causes, the 2022 ERCOT Winter SARA report incorporating those changes still shows a supply shortfall of approximately 10,000 MW to prevent load shed in another extreme winter weather scenario.[2] Thus, the challenge now facing the Commission is the need to solve two distinct reliability issues: (1) the need for fast-ramping, dispatchable resources that provide operational flexibility to ERCOT to address situations such as unforeseen changes in wind and solar production, large thermal resource outages, and solar ramping; and (2) the need for longer-duration dispatchable resources to address the cold winter night when the wind is not blowing. HEN believes that the right solution to the "long, cold winter night" scenario will be more than sufficient to solve the shorter duration "blue sky", "hot summer day," "missed sun and wind forecast" and "surprise thermal outage" scenarios.

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[1] Texas Comptroller of Public Accounts, Fiscal Notes October 2021 *Winter Storm Uri 2021: The Economic Impact of the Storm*, issued October 2021.

[2] Seasonal Assessment of Resource Adequacy for the ERCOT Region Winter 2022/2023, published by ERCOT on November 29, 2022.

It is important to signal to resources that can perform during all of these scenarios that they are needed now and in the future. In the coming month or two, the Commission should firmly establish the objectives for and key attributes of the Commission's improved version of E3's PCM proposal and establish clear multi-year transition measures using existing processes and products, so HEN and others can move aggressively now to invest in solutions for the ERCOT market.

HEN agrees with view that the LSERO and FRM options are not appropriate for ERCOT. These options rely heavily on administrative determinations of resource certification and they do not reward actual performance. The PCM is an innovative approach to address the shortcomings of the LSERO and FRM mechanisms. While it is complex and the details need to be thoroughly fleshed out, at its core, the PCM incents and rewards actual performance – a resource is only paid if it is available when it is needed, whether that is for an unexpected operational issue or for the cold winter night. HEN agrees with this premise.

However, for the PCM to be successful at addressing the long, cold winter night and the extreme weather scenario, there are fundamental modifications that must be made to E3's vision of the PCM. HEN encourages the Commission to identify and adopt these modifications to the PCM up front to provide a level of regulatory clarity and to clearly distinguish the Commission's PCM from that set forth by E3. Further, there is no question that it will require many months of meetings and dedicated work through the ERCOT stakeholder process to define the details of how the PCM would operate and be implemented. Once the details are agreed upon and adopted, there will be additional time required for ERCOT to modify its systems and implement the mechanism. In short, implementing the PCM will be a long, multi-year process. It is therefore essential that the Commission also adopt transitional measures to send clear market signals *today* so that HEN and other resource developers have the regulatory certainty they need to commit funding and commence construction of new dispatchable resources now.

This transition, or bridge, should satisfy the following requirements: (1) be quick to implement so that market signals are not further delayed, (2) incent the development of dispatchable resources, particularly long-duration resources; (3) reduce the frequency and cost of out-of-market mechanisms such as Reliability Unit Commitment (RUC) and (4) incent and reward performance. In HEN's view, a **Transition Plan** should consist of the following:

- Establish a reliability standard based on addressing the ERCOT winter SARA extreme case capacity shortfall;
- Expand procurement of ERCOT's forthcoming Contingency Reserve Service (ECRS) and existing Non-Spin service, designating *offline* Non-Spin to be an 8-hour product, with an up-front announcement by ERCOT of the quantities for all ancillary services to be procured for the next 3-5 years;
- Complete ongoing review of the appropriate Value of Lost Load (VOLL) in the context of setting the Operating Reserve Demand Curve (ORDC);
- Reduce the use of RUC through a judicious use of Reliability Must Run (RMR) contracts to delay the retirement of older, inefficient units; and
- Increase the energy efficiency goal in Rule 25.181 (e)(1)(A) and expand other demand response programs, that focus on residential winter heating (which was a major contributor to the extreme demand spike in February 2021).

Each of these measures utilizes existing tools in the Commission's and ERCOT's tool boxes and can be implemented without delay. Formally adopting these transition measures now would provide the level of regulatory certainty that HEN and other market participants need to develop new resources now, not waiting until several years from now. This time would allow the Commission, ERCOT and the stakeholders to focus on working through the details of an improved PCM.

RESPONSE TO COMMISSION 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?**

HEN does not view the fact that the PCM is designed specifically to address the ERCOT market (which itself is often considered unique) to be an unsurmountable obstacle. There are certainly flaws with the more common capacity constructs set forth in the LSERO and the FRM. The PCM is an innovative approach to address these flaws and to design a market approach that is consistent with, and does not harm, the ERCOT energy market. That said, it is reasonable to assume that it will take considerable time to develop all of the detailed rules and protocols governing the PCM, and additional time to implement the PCM. This is why it is critical that the Commission also adopt a robust transition plan as a bridge.

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 PCM as proposed and explained by E3 has several shortcomings that would prevent the mechanism from providing sufficient certainty for generation developers and thus there is a real risk that it would not produce the desired market entry by new dispatchable resources. However, HEN believes that the fundamental premise of the PCM – paying when resources perform – is appropriate and the Commission can modify the E3 PCM to create an improved performance mechanism that will incentivize market entry and performance of dispatchable resources, including thermal resources.

The E3 PCM requires the following modifications that should be explicitly adopted by the Commission if it adopts the PCM:

- **<u>Monthly Peak Net Load should be used to determine the hours of highest reliability risk.</u>**

E3 proposes that Performance Credits (PCs) would be awarded to resources during a predetermined number of hours (E3 suggests 30) "measured as the hours of lowest incremental available operating reserves."[3] E3 expects that these hours would often be correlated to the highest hours of peak net demand.[4] However, there are other events that can impact available operating reserves that are unpredictable, such as planned and unplanned outages. Outages can meaningfully impact operational reserves and the timing of when a resource goes into, and comes out of, an outage can significantly change the operational reserves. This is problematic because it creates the ability for generators with a large fleet to exercise market power by their timing of planned outages, and the timing of when the generator decides to come out of an outage, whether planned or unplanned. This creates the real risk of market manipulation through behavior akin to physical withholding. Monitoring this behavior would be challenging since the Independent Market Monitor (IMM) would be required to second-guess a generator's decisions with respect to the maintenance and repair of its assets.

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[3] Energy and Environmental Economics, Inc., "Assessment of Market Reform Options to Enhance Reliability of the ERCOT System" dated November 2022 (E3 Report), p. 22.

[4] *Id.* at 15.

In addition, because it will be difficult to predict the hours of lowest operational reserves, generators will be forced to offer in the forward market at a high price because of the uncertainty and the risk that generator will not accurately predict the hours of lowest operational reserves. This increases the prices that load would pay in the forward market for PCs.

Rather than create a system that is capable of market manipulation and exercise of market power, HEN recommends that the Commission base the hours in which the PC will be awarded on those hours of highest Peak Net Load, properly defined. The appropriate and commonly used definition of Peak Net Load in ERCOT is the maximum demand during the relevant time period net of intermittent generation which cannot be dispatched (i.e. wind and solar). E3 improperly includes energy storage as a non-dispatchable resource, which is simply not accurate.[5] Energy storage is a flexible and dispatchable resource that can both provide ancillary services and be dispatched by ERCOT through the Security Constrained Economic Dispatch (SCED) model.

Determining the hours in which a PC will be awarded based upon Peak Net Load has multiple advantages. First, it can be more easily predicted by both load and resources. For generation developers, this means that a potential revenue stream can be modeled, providing the needed certainty for investors and thus incenting the development of new dispatchable generation. For loads, using Peak Net Load means they would have the ability to manage their exposure to PCs since they could initiate demand response activities to reduce load during Peak Net Load hours. Additionally, as stated above, establishing the hours using Peak Net Load creates a more transparent metric relative to operating reserves.

In addition to awarding PCs based upon the hours of greatest Peak Net Load, the other key required change from the E3 proposal is that the PCs should be settled on a more granular, monthly basis.

- **<u>Performance Credits (PCs) should be procured and settled on a monthly, not annual, basis using the highest 4-8 hours of Peak Net Load each month.</u>**

E3 has proposed that the forward procurement of PCs be settled annually, based upon the 30 hours of lowest available operational reserves.[6] Presumably, an annual settlement would also require resources to offer PCs in the forward market prior to the annual settlement period. This

[5] *Id.*
[6] *Id.* at 22.

creates significant challenges for both resources and load. First, as discussed above, Peak Net Load is more predictable and appropriate than the hours of lowest operational reserves. However, even with the use of Peak Net Load, it is still extremely difficult to predict with any certainty a year in advance the top 30 hours of Peak Net Load and whether a generation resource will be available during those hours. For example, if all 30 hours were to occur during a single event on a day when a generator is undergoing a planned outage, the resource would not be able to perform and would not receive any PCM revenues for the entire year.

This inability to predict the PC hours a year in advance has several negative impacts. First, it is likely that it will cause higher clearing prices for the PCs that are offered in the forward market because generators must cover their risk of non performance. This result is not beneficial for Load Serving Entities as load will either bear the burden of increased costs or be unwilling to procure PCs in the forward market. In addition, an annual settlement period reduces the allocation of the PC revenues to a limited number of events, which increases the possibility that a generator is unable to collect any PC revenue. This could have the unintended consequence of increasing revenue uncertainty for investors, creating risk which leads to higher cost of capital and limited investment – the exact opposite of the goal of PCM to incent development of more dispatchable resources.

HEN recommends that the settlement period be modified to a monthly forward market and monthly settlement, with PCs awarded for a defined number of hours (i.e. 4-8 hours) of the highest Peak Net Load during each month. A monthly settlement of PCs will provide greater predictability of the Peak Net Load hours for both resources and load, which should bring down the forward prices for the PCs as resources are better able to predict the Peak Net Load hours for a month instead of an entire year. Additionally, a functioning forward market would allow loads to better predict, and respond to, monthly Peak Net Load hours, thereby managing their exposure to the PC costs. Finally, a more predictable revenue stream for resources will lower the cost of capital for development, which in turn should lower the CONE, and should therefore ultimately lower the cost of the PCs.

In addition to these fundamental elements of the PCM, there are many other important details that can and must be resolved through a Commission-led process or through the ERCOT stakeholder process. Most important of those relates to the determination of the PC prices. E3's proposed PCM design will result in highly uncertain PC prices from year to year which creates uncertainty and investor risk, thus reducing the likelihood of obtaining the desired investment in new generation. This uncertainty is caused by setting PC prices using the PC Demand Curve based on ERCOT's forecast of PCs for the following year and the actual amount of PCs generated – which can be vastly different than the forecasted amount. This implies that the price of PCs can randomly vary anywhere from $0 to the price cap and this price variation is not related to the ERCOT system meeting the reliability standard. A better approach which is more consistent with the goals of PCM would be to set PC prices based on ERCOT system's MW shortfall as shown in winter SARA extreme scenario or whichever other reliability standard is adopted. PC prices could be set using a curve that sets PC prices at the cap if the reliability standard is not met and sets PC prices lower if the reliability standard is exceeded – regardless of how many PCs are actually generated. This change will provide greater certainty to PC revenues to facilitate investment in dispatchable resources.

Finally, HEN believes that there certain elements of the Transition Plan should be continued when the PCM is implemented. HEN's response to Questions 8 and 9 describes the components of a Transition Plan that HEN recommends be adopted by the Commission. There are two elements of the Transition Plan that could be continued during the initial implementation of the PCM.

First, HEN strongly believes that it is essential that the Phase 2 market design reforms address the capacity shortfall shown in the Winter SARA extreme case such that Texas is protected from the ravaging effects of another extreme winter event. In the event that, after the PCM is fully designed, there is any uncertainty whether the PCM will properly incent the development of long duration, dispatchable resources, HEN suggests that the current offline Non-Spin service be shifted to be an 8 hour Non-Spin service, which should be implemented early during the transition period and continued with the implementation of the PCM.[7]

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

[7] HEN's modeling with a respected outside consultant has shown that a Non-Spin 8 product would effectively address the cold winter night scenario starting in 2025.

standard, at what level should the standard be set (e.g., how many MWh of EUE per year)?

HEN recommends that the Commission consider a different standard than the LOLE. LOLE does not capture the significance or magnitude of a load loss event. For example, using the LOLE standard, a 24-hour loss of 20,000 MWh and a one hour loss of 100 MWh are each considered one day of lost load, even though one loss was severe and potentially catastrophic and the other was a relatively minor event. The Expected Unserved Energy (EUE) standard instead measures the expected unserved MWh for the year. Using a Value of Lost Load (VOLL) and a net Cost of New Entry (CONE), the economically optimal value of EUE can be determined.

However, traditional reliability standards (whether LOLE or EUE) are not well-suited to take into account an extreme weather event since the traditional reliability standards are designed for expected outcomes and not for an extreme event. The most direct way to determine the resource need for Uri-type events is to use the ERCOT winter SARA extreme case shortfall amount. HEN believes that it is important that to recognize the importance of the SARA analysis since it is specifically focused on ERCOT and it provides a clear picture of the actual capacity required to prevent another significant load shed event.

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?**

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?**

HEN recommends that the reliability risk should focus upon the highest 4-8 hours of monthly Peak Net Load and PCs should be settled on a monthly basis. This important modification minimizes the uncertainty associated with the PCM while still providing equivalent reliability benefits. Please see HEN's response to Question 2 for a full discussion of this issue.

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?**

If the E3 PCM is modified by the Commission to use a monthly procurement and settlement of PCs that are awarded based upon availability during the highest 4-8 hours of Peak Net Load during that month (fully explained in HEN's response to Question 2), then the uncertainty risk associated with forward sale of PCs by generators would be reduced. Greater predictability of revenue streams in turn reduces the cost of capital imposed by investors, which reduces the total cost of new entry and should increase the funding available to develop new generation assets, which ultimately increases reliability.

If the forward market occurred in the month prior to the operating month, resources would have a greater ability to predict when the highest hours of reliability risk would occur during the next month. This approach might lead to lower PC costs in some months of greater predictability (i.e. summer) and higher PC costs in the winter when the possibility of storms could occur.

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

As discussed in the response to Question 2, there is a significant risk of market power abuse if the reliability risk is measured through operating reserves as proposed by E3 because generators with a large fleet could influence the operating reserves and the occurrence of the hours of lowest reserves simply by the way these entities manage outages. Thus, Peak Net Load should be used as the measure of reliability risk instead of operating reserves.

If this change is made, then a centrally cleared market through ERCOT, along with IMM oversight, should sufficiently mitigate the risk of market power abuse. HEN agrees with E3 that the potential for market power abuse is significant if only a bilateral market is used. The same is true if entities that have both resources and load (so called "gen-tailers") are permitted to self-arrange. This could remove a significant number of resources from the centrally cleared forward market and could increase the prices of PCs, placing independent LSEs at a disadvantage.

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?**

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 l-in-10 LOLE reliability standard?**

It is essential that the Commission adopt a robust "bridge" solution that can be adopted now and implemented quickly, using existing products. If the Commission were to adopt the PCM (or any other new market mechanism), it will take multiple years before such a product is in effect and those are years that the ERCOT market does not have. With the possibility of generation unit retirements, the Commission needs to take clear action now on a strong transition plan, using existing tools that are available.

The goal of a transition plan should be two-fold: assure reliability and send clear market signals to incent new generation investment now. To that end, a transition plan should satisfy the following requirements: (1) be quick to implement so that market signals are not further delayed, (2) create the additional market revenues required to incent the development of dispatchable resources; (3) reduce the frequency and cost of out-of-market mechanisms such as Reliability Unit Commitment (RUC) and (4) incent and reward performance.

HEN therefore proposes a Transition Plan with the following components:

- **Expanded procurement of ERCOT Contingency Reserve Service (ECRS) and Non-Spin**

Both ECRS and Non-Spin are current ancillary services that address the need for operational flexibility and reserves and employing them would not require additional modifications or implementation. ECRS (which is scheduled by ERCOT to go into effect in mid-2023) is a two-hour duration product that is designed to address operational issues that result in periods of high Peak Net Load, such as solar ramping or unexpected outages. Non-Spin is a four-hour duration product that has been used successfully by ERCOT since Winter Storm Uri to procure reserves. HEN proposes that ERCOT establish a quantity of ECRS and Non-Spin that would (i) address operational and reserve requirements and (ii) send a market signal that additional dispatchable generation is required in ERCOT. This should be accomplished by a public announcement by ERCOT of the quantities of ECRS and Non-Spin that it will procure for the next three to five years. This public announcement is a key element of sending clear market signals.

In addition, while the existing Non-Spin 4-hour product incents longer-duration dispatchable resources, HEN believes that a longer duration Non-Spin product, such as an 8-hour Non-Spin ancillary service, could be designed to directly address the problem of a long, cold winter night with no wind ("the extreme weather event"). HEN would support transitioning the existing *offline* Non-Spin into an 8-hour Non-Spin product as soon as practicable during the transition.

- **Completion of the ongoing review of the Value of Lost Load (VOLL) in adjusting the Operating Reserve Demand Curve (ORDC);**

The Commission's Phase 1 – Enhancements to the Current Market Design identified certain changes to be made to the ORDC.[8] While some of those changes have been implemented, the Value of Lost Load (VOLL) has not been re-evaluated. HEN recommends that the Commission complete this Phase 1 activity and determine the appropriate VOLL "based on quantitative analysis of new revenue to the market that would be directed to reliable generation assets during scarcity events" as set forth in the Phase 1 Market Blueprint.

- **Replacement of excessive RUC with a judicious use of Reliability Must Run (RMR) contracts to delay the retirement of older, inefficient units**

Since Winter Storm Uri, ERCOT has relied on the Reliability Unit Commitment (RUC) process to dispatch older resources. ERCOT has greatly increased the use of RUC since June 2021. The IMM notes in its 2021 State of the ERCOT Market Report that 4,052 unit-hours of RUC instructions were issued in 2021, compared to 224 unit-hours in 2020.[9] More concerning, the IMM had identified a withholding strategy that had emerged with the increased RUC actions.[10] In short, RUC is an out-of-market action that needs to be replaced with more transparent market solutions.

Recognizing that the older thermal plants are moving toward retirement (and could be forced into retirement under the Cross-State Air Pollution Rule (CSAPR)), but are still needed to operate in certain conditions until new resources are operational, HEN suggests that ERCOT consider a judicious use of Reliability Must Run (RMR) contracts for these resources. RMR, the rules for which are currently in effect, uses a cost-based compensation for the operation of these projects when needed; however, unlike RUC, these units are not otherwise permitted to

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[8] *Review of Wholesale Electric Market Design*, Project No. 52373, Approval of Blueprint For Wholesale Electric Market Design and Directives to ERCOT issued January 13, 2022.

[9] Potomac Economics, *2021 State of the Market Report for the ERCOT Electricity Markets*, May 2022.

[10] *Id.* at 104-105. The Protocols were subsequently amended through NPRR 1092 to address the specific withholding strategy identified by the IMM.

operate or bid into the market. Using RMR, in conjunction with the enhances use of ECRS and Non-Spin, should reduce ERCOT's reliance on out of market RUC activity

- **Enhanced use of energy efficiency and demand response programs**

There are several steps the Commission can take now to increase energy efficiency and demand response. First, a primary cause for the extreme customer demand during Winter Storm Uri was residential electric heating. The Commission would be well-served to expand existing energy efficiency programs administered by the Distribution Service Providers (DSPs) to specifically target improvements related to residential electric heating, including weatherization programs and retrofitting and replacement of inefficient heating systems. This would include, but is not limited to, increasing the energy efficiency goal in Substantive Rule 25.181 (e) (1) (A).

Second, because it is clear that periods of high net peak demand are driving the need for additional dispatchable resources, the Commission could consider creating incentives for demand response during periods of high net peak demand. For example, consider allocating Transmission Cost of Service based on net peak demand intervals in both summer and winter rather than the four coincident summer peaks.

Finally, as more distributed energy resources (DERs) are developed, HEN expects that load resources will play an increasingly important part in creating a reliable grid. The Commission could adopt policies to permit greater participation in the market by Distributed Energy Resources (DERs), including establishing policies for the use of the utilities' distribution systems that support the development of DERs.

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

E3 measured expected consumer cost for LSERO, FRM and PCM using a Cost of New Entry (CONE) that, in HEN's view, is too low. E3's CONE was \$93.5/kW-year. This is lower that the CONE currently utilized by ERCOT, and ERCOT's CONE has not been updated since 2012.[11] Based upon HEN's experience in the market using current cost of capital assumptions, a more reasonable CONE would be between \$120 - \$124/kW-year. If a higher, more realistic CONE is used, then the cost of each of the alternatives will increase. To properly calculate an estimated

[11] ERCOT's current CONE is \$105/kW-year, which was based upon a Brattle Group study from 2012. ERCOT has been considering an update to the CONE used to calculate Peaker Net Margin, but it has not yet been updated.

cost of the PCM, an updated CONE should be calculated, based on current market conditions. In addition, the impact of the cost of capital on CONE, and ultimately on the cost of the PCM, highlights the need to modify the PCM so that the revenues are relatively predictable, which will help to lower the risk perceived by investors, and thus lower the cost of capital for new development.

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.

Please see HEN's response to Question 9.

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?

HEN's main concerns with the E3 DEC proposal are the price suppressing energy offer incentives and market price suppression caused by DEC resource dispatch. These thwart the Commission's goal of incenting new investment in dispatchable resources. In order to address both these issues, HEN recommends that the DEC should be modified as follows:

i. DECs are awarded on a monthly basis for being available and offering into the real time energy market or receiving an ancillary service award in the day ahead market during the 4-8 highest Peak Net Load hours during that month.

ii. To address the price suppression concern, any potential price suppression from DEC resource energy deployment by SCED should be reversed by applying the Reliability Deployment Price Adder and such resource capacity should not be considered as contributing to "operating reserves" in the Operating Reserve Demand Curve (ORDC). This will make other resources in the energy market indifferent to the addition of new subsidized DEC resources.

iii. Loads also only pay for new long-duration dispatchable resources when these resources are built. This cost paid by the LSEs can be considered an insurance premium for the next extreme weather event. An LSE's payments for DECs will also be somewhat offset by lower Non-Spin and ECRS prices due to supply of those ancillary services by DEC-eligible resources.

HEN appreciates this opportunity to offer comments and is available for any questions the Commission may have.

Respectfully submitted,

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HUNT ENERGY NETWORK L.L.C. (HEN)
EXECUTIVE SUMMARY OF COMMENTS ON E3 REPORT
DECEMBER 15, 2022

The regulatory uncertainty surrounding the ERCOT market design creates risk for developers and their investors, increasing the cost of the capital and hampering new generation investment in ERCOT. The Commission needs to take decisive action now to establish clear market signals to support development of dispatchable resources, including resource that can generate for long durations.

Performance Credit Mechanism

- HEN agrees with the core premise of the PCM– to pay for performance from resources that are available when needed, whether during an extreme weather event, a cold winter night with no wind, a "blue sky" day, or a day with unexpected generation outages.
- The Commission should firmly and clearly establish the objectives for and the key attributes of an improved Commission PCM proposal which addresses the critical flaws in the E3 version of the PCM. These flaws create uncertainty, increasing regulatory risk for developers and their investors. The critical modifications that should be established by the Commission are the following:
  - Monthly Peak Net Load (peak demand less solar and wind generation) should be used to determine the hours of highest reliability risk.
  - Performance Credits should be procured and settled on a monthly, not annual basis using the highest 4-8 hours of Peak Net Load each month.

Bridge to the PCM: Transition Plan

- Developing the detailed market rules for a successful PCM and implementing those market rules will be a multi-year process, but the ERCOT market needs new resources now – not five years from now. The Commission should therefore also adopt a comprehensive bridge, or transition plan to be implemented immediately.

- The Transition Plan should include the following:
  - Establish a reliability standard based on addressing the ERCOT winter SARA extreme case capacity shortfall;
  - Expand procurement of ERCOT Contingency Reserve Service (ECRS) and Non-Spin, redefining offline Non-Spin to be an 8-hour product, with an up-front announcement by ERCOT of the quantities to be procured for the next 3-5 years;
  - Complete ongoing review of the appropriate Value of Lost Load (VOLL) in the context of setting the Operating Reserve Demand Curve (ORDC);
  - Reduce the use of RUC through a judicious use of Reliability Must Run (RMR) contracts to delay the retirement of older, inefficient units; and
  - Increase the energy efficiency goal in Rule 25.181 (e)(1)(A) and expand other demand response programs that focus on residential winter heating (which was a major contributor to the extreme demand spike in February 2021).