Potomac Economics, the Independent Market Monitor (IMM) for the wholesale market in the Electric Reliability Council of Texas, Inc. (ERCOT) region, appreciates the opportunity to file these comments in Project No. 54335, *Review of Market Reform Assessment Produced by Energy and Environmental Economics, Inc. (E3)*. These comments include select responses to the market reform assessment report filed by E3 (Report). We are not providing comments on the proposals that the Commission indicated it is not considering at its November 10, 2022, open meeting.

I. **Comments on the Analysis of ERCOT’s Current Market**

To begin, we discuss the current incentives regarding the ERCOT market and E3’s analysis of the market in the Report. This is essential because all of the Phase II market design proposals would supplement the existing market to achieve the Commission’s stated objectives, such as setting a reliability standard and ensuring the market design can meet that standard. Therefore, beginning with an accurate understanding of the current market incentives is critical.

A. **Revenues and Investment Incentives Provided by the ERCOT Market**

We continue to believe in the effectiveness of the energy-only market. The Commission adopted significant changes to the energy-only market design by implementing adjustments to the Operating Reserve Demand Curve (ORDC) under Phase I of the market redesign effort to continue to incent dispatchable resources that are flexible and highly available. Although the
effects of these changes will take some time to manifest, they provide more meaningful incentives than any of the other market design proposals under consideration and time should be given to fully assess the impacts before we deviate from the energy-only market design.

The Phase I changes to ERCOT’s shortage pricing mechanism via the ORDC have increased real-time market energy revenues by $1.7 billion in 2022 through November 30. This substantial increase in energy revenues alone greatly enhances the incentives for existing resources to remain in operation and for entities to build new dispatchable resources. This statement does not even take into account the substantially increased ancillary service revenues arising from increased requirements put in place in July 2021. The following figure shows that the energy-only market has been effective at motivating participants to invest in new dispatchable gas generation.

Dispatchable Natural Gas Additions since 2014

[Chart showing dispatchable natural gas additions from 2014 to 2022]
The figure above shows that investors respond to the expected revenues produced by the ERCOT market. Once again, given the substantial increase in revenues generated by the most recent ORDC shift in January 2022, we are confident that investment in dispatchable gas resources will continue and possibly accelerate.

Additionally, the ORDC parameters will result in further increases in revenues for dispatchable resources in the future as more intermittent resources enter the market, which is not recognized by E3 in their analysis. E3 assumes static mu¹ and sigma² for the shape of the ORDC. These parameters are meant to shift according to operational realities and can greatly impact future revenues and investment signals. In an equilibrium fleet with roughly 40 GW of wind and 40 GW of solar, the mu and sigma values should be significantly larger due to increased hour-ahead uncertainty related to renewable forecasting, which would result in larger revenues from the ORDC during intervals of reliability risk. This will strengthen incentives to be available in these time periods and to build and maintain more reliable generating resources in the long run.

It is important to understand why shortage pricing under the ORDC is so effective in promoting dispatchable generation that is flexible and available. The revenues generated under the ORDC are only paid to the resources that are providing energy and reserves when the system is tight, which is predominantly the dispatchable resources. To illustrate this, consider the following two classes of resources:

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¹ Mean (Mu or μ); the mean value of the loss of load probability (LOLP) distribution.
² A standard deviation (Sigma or σ) of the LOLP distribution.
- **Dispatchable Gas Resources**: produce less than 43% of the energy in ERCOT, have received more than 61% of the 2022 ORDC revenue for energy.
- **Wind Resources**: produce more than one quarter of the energy in ERCOT, have received only 7.4% of the 2022 ORDC revenue for energy.

**B. Future Retirements under the Current ERCOT Market**

Based on the brief yet strong incentive effects of the Phase I changes generated in 2022, we find the Report’s assumption that 11 GW of existing resources will retire in the coming years unsupportable and inconsistent with generators’ economic incentives. The overstated retirements in the Report are driven by the assumption that resources will retire if their net margin is less than the Cost of New Entry (CONE). This economic logic is flawed – existing resources are only expected to retire if their net margins fall below their “going-forward costs” or their costs of remaining in operation. Because going-forward costs are generally much lower than the CONE of a new resource, this economic assumption in the report will result in unrealistically high projected retirements.

While we have continuing concerns with some of the inputs to the ORDC shape as a result of the Commission’s Phase I change, we nevertheless conclude that the increase in net revenues that existing generators will continue to receive as result of the Phase I changes, even with the expected significant expansion of intermittent resources in ERCOT, will cover virtually all of these resources’ going forward costs of remaining in operation. Hence, we find it likely that only a very small portion of the 11 GWs of retirements will actually occur by 2030.

**C. Reliability under the Current ERCOT market**

The poor modeling of expected retirements under ERCOT’s current market (described in the Report and discussed above) results in a 2026 base case Loss of Load Expectation (LOLE) that is implausibly high. We find that the current market with the Phase I changes ordered by the
Commission is achieving and will likely continue to achieve the one-in-ten reliability standard proposed in the Report. This conclusion follows from the fact that the strengthened incentives and revenues under the Phase I changes will sustain the existing base of dispatchable generation and render widespread retirements extremely unlikely. This is critical because the conclusion that further design changes are necessary to motivate needed investment in dispatchable resources is entirely based on the Report’s assumption that substantial quantities of existing dispatchable resources will retire in the coming years.

The primary reliability issue that we identify associated with the rapid increase in intermittent generation is one of operational flexibility. To address this issue, we continue to recommend, as we did in our October 15, 2021, comments, that ERCOT adopt a 2- to 4-hour uncertainty product.3 Such a product can be deployed to start up longer lead-time units when ERCOT detects that operating conditions are departing from expected conditions (i.e., the “uncertainty” inherent in forecasting models or in thermal forced outage expectations). This product would offer substantial market benefits without disrupting the existing market design, as it would:

- Allow all of ERCOT’s prices to more fully reflect the costs of managing uncertainty;
- Set more efficient prices as the system begins to become tight and becomes short of these uncertainty reserves;
- Reduce ERCOT’s reliance on out-of-market actions, such as Reliability Unit Commitments (RUC) because such reserves would be procured through the market; and
- Reduce uplift costs associated with ERCOT’s out-of-market actions.

This product would be procured in the day-ahead market based on factors such as intermittent renewable generation, load forecast error, and thermal generation forced outage probabilities at a very high confidence interval. One can think of the uncertainty product as non-spinning reserve service (non-spin) with a longer start time requirement. However, the pool of resources that would qualify for the uncertainty product (including demand response) will be higher than the pool for non-spin and therefore the competition to provide it will be stronger in the uncertainty product market. Implementation time should not be a significant barrier because much of the logic can be lifted straight from non-spin parameters and simply repurposed. As an added benefit, the excess non-spin requirements can be reduced, and duration requirements eliminated, immediately upon implementation of the uncertainty product.

We also continue to recommend prioritizing the implementation of real-time co-optimization (RTC). The energy-only market is the best market design suited to dynamically respond to changes on the ERCOT grid, and RTC will only enhance this capability and allow ERCOT to best use the existing capacity on the system. The most important improvement to the ERCOT market over both the short and long term will be the implementation of changes to the real-time market to allow it to jointly optimize the scheduling of resources to provide energy and ancillary services in each dispatch interval. This Commission-approved project was delayed in 2021 and is now on hold to start the multi-year project until at least mid-2023 due to resource constraints caused by the market reform efforts. Implementation of RTC will significantly improve the real-time coordination of ERCOT's generation and load resources, reduce overall production costs, improve shortage pricing, and eliminate the flaws inherent in the ORDC.

4 ERCOT RTC Update to Technical Advisory Committee (TAC), January 31, 2022.
These improvements will be key to reliably operating a grid with a different resource mix as additional wind, solar, and storage resources enter the ERCOT market.

II. COMMENTS ON THE ANALYSIS AND PROPOSALS IN THE REPORT

Given the tangible effectiveness of the Phase I changes to date and the significant potential drawbacks and costs of Phase II proposals, we do not recommend that the Commission move forward with any of the Phase II proposals at this time. The Performance Credit Mechanism (PCM) proposal is a less effective and efficient means to facilitate performance by ERCOT’s generation fleet than the energy-only market. The energy-only market is an effective pay-for-performance mechanism and should be retained in full without adding an unnecessary separate availability payment structure that would be difficult to accurately hedge or predict due to its ex-post procurement. Of the PCM or the BRS, we find that the PCM is preferable to the BRS in that it would be less disruptive to ERCOT’s current market.

A. Comments on the Analysis in the Report

Our largest concern with the Report is the apparent flaw in E3’s analysis of the reliability of the current energy-only market, as discussed in the previous section. In this section, we describe some additional concerns with the analysis. We note similar market costs are reported for the new proposals in the Report at long-run equilibrium. However, the evaluations of the proposals assume perfect capacity decisions (no overbuild or over-forecast), no market power abuse, and optimal dispatch of ERCOT’s resources. Evaluating these issues for each proposal is important for determining the accuracy of those cost estimates.

E3 also did not model ERCOT’s persistent conservative operational posture that discounts the Responsive Reserve Service (RRS) provided by Load Resources and requires 6,500 MW (and sometimes 7,500 MW) of reserves in real-time from generators and from loads
providing non-spin. These higher reserve requirements affect ERCOT's out-of-market actions and the Report did not contain any commentary on how to reduce ERCOT's reliance on Reliability Unit Commitment (RUC).

The CONE value used throughout the Report is lower than current official ERCOT CONE of $105,000/MW year. This CONE was established in 2012 and may be understated given recent supply chain issues and inflationary pressures, though a new study would need to be performed to confirm. A higher CONE will result in higher cost estimates of the Phase II proposals.

Finally, E3 uses high load growth assumptions for the 2026 case that likely assumes some additional crypto-mining load and electric vehicles, but E3 uses static 2022 values for price responsive demand and ERCOT Four Coincident Peak (4CP) response. We believe it is more reasonable to assume that these values will go up at least proportional with the load growth, if not more given the nature of much of the growth assumptions.

B. Backstop Reserve Service (BRS) Proposal

We do not recommend the BRS proposal, individually or in concert with any other proposal, because is not consistent with the economic principles of ERCOT's competitive electricity market. It represents an out-of-market procurement that is not based on supply and demand fundamentals. Essentially, implementing BRS is planning for market failure rather than continuing to design the market to succeed.

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5 ERCOT Noda Protocol Sec. 4.4.11(c).
6 4CP is the average Coincident Peak demand reading set by an electric load during the 15-minute interval with the highest coincident peak load in each of the four (4) months associated with ERCOT's 4CP season (June, July, August and September). 4CP response is certain loads reducing their consumption during these 15-minute intervals in an attempt to reduce the amount they are required to pay in transmission charges.
The Report assumes that the BRS would primarily procure new resources, which we find unlikely and unsupportable. Old generators contemplating retirement could offer to sell BRS at a price much lower than new resources because they generally receive relatively low net revenues due to their lower efficiency and higher marginal costs of producing energy. Therefore, their opportunity cost of selling BRS is low compared to new resources since new resources would have to earn their full CONE in BRS payments in order to provide BRS.

This assumption is important because it understates the cost estimate. If existing resources sell BRS, they will be effectively removed from the market and their offers will be set to the cap, as contemplated in the Report. This would substantially increase prices and market costs, particularly if they are located in transmission constrained areas and are needed to manage congestion. These cost increases were not estimated by E3 in the Report since they assumed BRS would be provided by new resources and since they did not consider any transmission issues. Hence, we disagree with the assertion in the Report that the “the resources procured through the BRS mechanism do not impact price signals present in the Energy-Only design, since BRS resources will only be deployed at the end of the bid stack to prevent any impacts to real-time energy price formation for other resources.”7 Removing up to 5,630 MW of existing capacity from the market dispatch would certainly affect price signals.

In the long run, however, designing a program that would build new resources to be set aside to only be used during emergency conditions would be far more costly for consumers in Texas. Therefore, although the proposed BRS would result in significant price increases in the near-term, it is much less costly than some public proposals that would procure only new resources to be back-up reserves.

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7 E3 Report at 50.
The IMM disagrees with the design element of BRS that requires BRS resources offer at the cap. If the BRS is adopted, these resources should be treated like RUC resources for price formation purposes (related to the ORDC and reliability deployment price adders). In this way, they could be used to resolve transmission violations. More discussion is needed to determine an appropriate offer floor for BRS resources.

The IMM further disagrees that a pay-as-bid model should be considered for BRS. There is a well-documented incentive and efficiency issue with pay-as-bid auctions based on real-world experience (see IMM comments on Firm Fuel Supply Service, April 29, 2022).8

Finally, the IMM is of the opinion that there is no need to institute the BRS as a “bridge” ahead of the PCM, if the PCM is selected. E3 notes that “today's system appears to be close to the 0.1 days/yr benchmark” and “[w]ithout further adjustments to the resource mix beyond CDR additions and retirements, the "pre-equilibrium" 2026 portfolio would achieve an LOLE of 0.02 days per year, more reliable than the common industry benchmark of 0.1 days per year.”9 As we state above, E3’s modeling of retirements under the current market is flawed and it is extremely unlikely that there will be a shortfall of 5,630 MW in 2026. Setting aside the methodological concerns, the changes in fleet composition to reach the long-run equilibrium levels could not even realistically be achieved within this timeframe. Therefore, there is no need for the BRS or any other market design proposal to be implemented quickly as a bridge to longer-term market design.

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9 E3 Report at 46.
The existing ERCOT protocols already have a “backstop” for temporary retention of retiring resources: the Reliability Must Run (RMR) process. While RMRs should be avoided to the maximum extent possible, the procurement process and settlement for these are already in place and already offer the interim safety net that the Commission may be considering.

C. PCM Proposal

As discussed above, the Phase I changes ordered by the Commission are far more effective and more sound economically than the Phase II proposals evaluated in the Report. Nonetheless, we find that the PCM raises fewer concerns than the BRS proposal, although ultimately we do not recommend its adoption. We provide comments in this section on the proposal and specific elements of it that could be improved. We are concerned with the design of the forward market, with the inefficient signals that may result from participants trying to predict the PC hours, and with the challenges that Load-Serving Entities (LSEs) may face in hedging the moving target of PC quantities.

The reason we find that the PCM is preferable to the BRS is that it would be less disruptive to ERCOT’s current energy-only market. It would compensate generators in a manner that is somewhat similar to shortage pricing by rewarding resources that are available and contributing to reliability during the tightest market conditions. However, it is a less predictable source of revenue and performance incentives than the revenues provided under the ORDC during tight conditions.

Eligibility to Participate. Allowing virtual participants in the forward market is a threshold issue that must be addressed if this design moves forward. The benefits of allowing virtual participants are numerous. If there are not enough self-accredited megawatts (MWs) or not enough MWs offered by generators to meet the demand of buyers, traders will make up the
difference. The resulting forward Performance Credit (PC) value will represent a market signal for entry and performance ahead of the operating year. This will also help smooth the revenues year to year. Virtual participation will also provide needed liquidity in the forward market, mitigate market power in the forward market, and help converge the forward market and the residual market. We are concerned that the forward market will not perform competitively in absence of this participation, which would result in inadequate or illiquid hedging opportunities for participants.

Self-Accreditation Monitoring. We agree that self-accreditation would be an issue that IMM would need to monitor. The existing rules would need to be modified to allow effective monitoring and potential enforcement for this new product.

PC Hour Uncertainty. We note that, depending on how the “highest reliability risk” hours are measured, it could be very difficult to successfully predict with reasonable accuracy when they will occur. The difficulty in prediction is a particular problem for loads desiring to reduce their costs by reducing their consumption during the PC hours.

The difficulty of successfully predicting the PC hours will cause market participants to behave inefficiently. For example, manufacturers may stop making their products to avoid paying for PCs when the actual grid conditions are relatively mild. Similarly, too many generators may decide to commit in those conditions as well, in an attempt to generate PCs. This may lead to price suppression in the real-time market due to the inefficient commitment decisions. This could cause convergence issues between the day-ahead and real-time markets that reduce the efficiency of the market outcomes. It could also undermine the long-term investment and retirement signals provided by the ERCOT market. Ultimately, this would raise costs and could reduce reliability. A monthly measurement period could exacerbate these
inefficiencies. It is advisable to design the mechanism in such a way as to retain as much of the existing market signals in the energy market as possible.

*PC Hour Definition.* The Report did not define the periods of “highest reliability risk.” E3 implied at the December 2, 2022, technical workshop that periods of “highest reliability risk” would be based on ORDC reserves. We recommend instead that the Physical Responsive Capability (PRC) metric should be used for “highest reliability risk,” as it is an actual reliability metric rather than a market metric, though we caution that there will be some inefficiencies with this approach until ERCOT implements RTC. We recommend that it be calculated as the average PRC value over the hour, with adjustments for reliability actions such as firm load shed.

We do not recommend using peak net load as the metric. It would not address reliability risk related to higher than expected thermal generation outages. If it is used, we note that E3 defined it in such a way as to exclude energy storage resources from the contribution to “dispatchable” capacity. Based on the characteristics and operation of storage resources by ERCOT, we believe they should be included as dispatchable capacity in the peak net load. Hence, we recommend that peak net load should be defined as peak load minus intermittent renewable resource output.

*Eligibility for PC Credits.* It is unclear whether all resource types can earn PCs during the “highest reliability risk” intervals. The PCM will produce its most effective and efficient incentives if the generation of PCs are defined to be technology neutral. To do otherwise would undermine the performance incentives provided by the PCM and be unnecessarily discriminatory. Hence, we recommend that any resource contributing to reliability by being online and available during high-risk hours be eligible to receive PCs. In addition, during times that are evaluated as “highest reliability risk” but not actually in or near scarcity (as may often
occur during shoulder months if PCs are evaluated monthly or seasonally), resources that are offline and available for commitment within an established startup time (perhaps 4-8 hours) should be eligible to earn PCs despite not being online. This could be accomplished by setting a PRC minimum that would trigger the different eligibility. This would reduce the impact to real-time market prices during those scenarios and reduce one of the inefficiencies inherent in the PCM.

The Demand for PCs. Setting a reasonable price for the PCs will be a critical component of such a market design. To facilitate this, it is essential that the demand for the PCs in the residual market reflect the reliability benefits of procuring them. The less PCs ERCOT is able to procure based on the available supply, the higher the marginal value of the PCs. Conversely, as ERCOT is able to procure more PCs from the existing supply, the less valuable they become at the margin. This dynamic can only be reflected in the pricing of the PCs by defining and utilizing a sloped demand curve that would be used to clear the PCs. The prices set under such a curve will be sensitive to the load growth and reserve assumptions, as well as the parameters established that govern the shape of the curve. Therefore, we recommend ERCOT develop a sloped demand curve for the PCM that reflects, as accurately as possible, the marginal reliability benefit provided by the resources selling the PCs, if the PCM is implemented.

Finally, a demand curve constructed based on inaccurate assumptions could result in inefficient outcomes (such as very low reliability risks hours clearing at high prices or shortage hours clearing at zero). There are implementation options to consider that could improve the determination of the net CONE upon which the demand curve is based, such as calculating the net CONE based on the actual energy and ancillary services revenues from the same measurement period to offset CONE on an ex-post basis.
D. Conclusion

The IMM appreciates the opportunity to share these comments and looks forward to further participation in the market redesign effort.

Respectfully submitted,

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EXECUTIVE SUMMARY OF POTOMAC ECONOMICS’ MARKET REFORM ASSESSMENT COMMENTS

Potomac Economics, the IMM for the wholesale market in the ERCOT region, provides the following comments in Project No. 54335, Review of Market Reform Assessment Produced by Energy and Environmental Economics, Inc. (E3):

Given the magnitude of the Phase I changes\(^1\) and the drawbacks and costs of Phase II proposals, we do not recommend that the Commission move forward with any of the Phase II proposals. We believe the current market will produce revenues sufficient to prevent the widespread retirements predicted in the Report and will incent investment in new dispatchable generation. Our comments describe flawed analytic criteria employed by E3 and correcting this allows us to conclude that the current market will likely continue to more than satisfy the 1 in 10 reliability criteria cited in the Report.

The BRS proposal is not consistent with economic principles because it represents an out-of-market procurement that is not based on supply and demand fundamentals. We expect that the BRS would be procured from existing units; this is important because removing a large amount of existing capacity from the market dispatch will significantly affect costs in the short run that were not quantified in the Report. In the long run, however, this is superior to designing a different program that would build new resources to be set aside to only be used during emergency conditions, which would be far more costly for consumers in Texas.

We find that the PCM proposal is a less effective and efficient means to facilitate performance by ERCOT’s generation than the energy-only market. We are of the opinion that the PCM would be less disruptive to ERCOT’s current market than BRS, however. Our comments address a number of key elements of a PCM that would need to be developed or clarified that could significantly affect how it will perform. In addition, we discuss the fact that uncertainty about when PC measurement hours will occur may cause market participants to behave inefficiently by reducing load or committing uneconomic generation when PC hours are predicted but do not materialize. This outcome would reduce the societal benefit of the PCM.

\(^1\) The Phase I changes to ERCOT’s shortage pricing under its Operating Reserve Demand Curve have increased real-time market energy revenues by $1.7B in 2022 through November 30.