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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**

THE ADVANCED POWER ALLIANCE AND AMERICAN CLEAN POWER ASSOCIATION COMMENTS

The Advanced Power Alliance (APA) and the American Clean Power Association (ACP) appreciate the opportunity to respond to the Public Utility Commission of Texas (Commission) Staff's Questions for Comment in Project 54335: *REVIEW OF MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3).* The comments submitted do not reflect the opinions of any individual member company.

I. INTRODUCTION

The Advanced Power Alliance (APA) and the American Clean Power Association (ACP) serve as the voice of more than 800 member companies that represent a diverse cross-section of the world's leading energy companies, energy investors, energy consumers, and power generation manufacturers from across the clean power sector that are driving high-tech innovation through the development of generation assets including wind, solar, and energy storage, spurring massive investment in the U.S. economy while creating jobs for American workers.

Projects developed by our member companies and investors generate local tax revenue for schools, services, and infrastructure, as well multi-generational income for Texas landowners, mainly in rural Texas. Our members' projects help to create cleaner air, water, and improved human health.

II. GENERAL COMMENTS

APA and ACP appreciate the opportunity to provide comments on the staff questions relating to the market reform assessment prepared by E3 and the Performance Credit Mechanism (PCM). We direct the bulk of our comments to the questions posed in the staff memorandum that are central to the issues addressed by the commission at the legislature's direction. Where possible, we have grouped related questions to allow for the most efficient response to the staff questions. To do so, however, requires first precisely identifying the market issues that the E3 assessment and market design proposals are intended to address. This is especially true when the changes recommended by E3 and those recommended by the commission impact the fundamentals of a $28 billion dollar market that profoundly shapes the lives and well-being of millions of Texans.

APA and ACP share the view held by many stakeholders that the E3 analysis was deeply flawed and these flaws undermine E3's ultimate conclusions with respect to the various market designs. As the flaws in E3's assumptions are well-documented elsewhere in this project, we will not repeat all of them here in the interest of brevity.

APA and ACP note, however, that the conclusion in the E3 report that the market requires 5630 MW in new dispatchable capacity is premised upon the exit of approximately 11 GW of existing thermal generation from the market by 2026. The Independent Market Monitor (IMM), among others, has questioned this conclusion and the assumptions on which it is based, recently stating, "... I would caution you against taking that 5630-megawatt number as a like set in stone number that needs to be replaced ... I would not take that number as set in stone or necessarily accurate, I think that's overstated."[1] This central conclusion and the flawed assumptions that underpin it severely compromise the E3 assessment's evaluation of various market design options.

As one legislator noted at a recent hearing on the E3 assessment, "... I have yet to see any issue of this importance that engenders this much disagreement and this many diverse opinions

[1] Testimony of Independent Market Monitor Carrie Bivens, Senate Business and Commerce Committee November 17, 2022.

by people who really really know what they're talking about."[2] We believe that this is because there is a lack of clarity, or at least agreement, on i) market needs based on clearly defined objectives, ii) how each Phase II proposal does or does not meet each objective, as well as how each interacts with Phase I proposals, and iii) how products and services designed to meet the reliability needs of the ERCOT region should be sized based on more robust resource adequacy metrics, which we address in response to Question 3.

As indicated in a letter to the commission signed by all members of the Senate Committee on Business & Commerce dated December 1, 2022, now is the time to take a step back and "define the reliability goals for the ERCOT region prior to moving forward with any significant market redesign." To assist the commission, the legislature, and stakeholders in evaluating the PCM and any proposed bridge or alternative proposals, APA and ACP's comments will evaluate proposals through the lens of three market objectives:

- **Resource Adequacy.** Does the market have sufficient effective capacity, or is there a structural capacity shortfall that produces a risk of outages beyond an acceptable level of risk? A reliable system requires sufficient effective capacity in the system to meet demand with a diverse portfolio of resources at least cost based on resource adequacy metrics and probabilistic analysis that provide insight into the nature of system needs across all hours and a wide range of conditions.
- **Resource Availability.** Are resources available when called upon to meet system conditions, including extreme heat or cold, both at the generation level and with respect to transmission system constraints to get electrons from generators to customers? This was a significant issue during Uri when significant capacity was unable to respond due to mechanical failures and lack of access to fuel for thermal units resulting in sustained correlated outages across the system.
- **Operational Flexibility.** Does the market have the appropriate tools to address operational needs in near real-time conditions when there are variations in load, forced outage rates, or output from variable resources? Targeted ancillary services are designed to meet these real-time needs and respond to a rapidly changing grid.

APA and ACP also urge that any solutions be based on first principles of efficient market design–namely, that any market design reforms should be non-discriminatory, transparent and

[2] Comments of Senator Nathan Johnson, Senate Committee on Business & Commerce Hearing, November 17, 2022.

should enable easy market entry and exit so that all resource types and market participants can effectively evaluate and respond to market signals (prices) and thereby achieve an optimal resource mix at least cost.

III. RESPONSES TO COMMISSION STAFF'S QUESTIONS

Responses to Staff's question are organized by subject matter below.

A. Questions related to reliability standards

<u>Question 3</u>. *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)?*

Implicit in this question is the assumption that a reliability standard should be adopted in ERCOT. APA and ACP believe that the changing nature of both supply- and demand-side resources and more extreme weather warrant the use of more nuanced resource adequacy metrics to understand system needs better and more precisely combined with a non-discriminatory assessment of the reliability contributions of all resources.

The 1-in-10 standard or 0.1 LOLE is a relatively blunt instrument. Because the 1-in-10 standard considers only the likelihood of an outage occurring and not the amount of unserved demand that is expected to result, it can have the effect of overstating capacity needs. As E3 notes, LOLE also fails to capture duration as the because the 1 day in 10-year load shed event "may last anywhere from seconds to hours."[3] As a recent report notes, the types of reliability events to be addressed today are much more varied, and a more diverse array of resources including storage, demand response, and load flexibility exist today to meet reliability needs. As a result, more refined reliability metrics are needed because:

> "… understanding the size, frequency, duration, and timing of potential shortfalls is essential ***to finding the right resource solutions***. LOLE is an inadequate metric in a world of more varied shortfall events because it provides limited information on shortfall events' size and duration. This makes it difficult to know the true impact of potential

[3] E3 at 43.

shortfalls and nearly impossible ***to determine the types of resources necessary to reduce the number of shortfalls."***[4]

Notably, the North American Electric Reliability Council ("NERC") utilizes as reliability metrics both Expected Unserved Energy (EUE), which captures the magnitude and duration of reliability events by calculating the average amount of unserved energy in megawatt hours of demand that will not be served across all hours in a given time period, and Loss of Load Hours (LOLH), which captures the number of hours per year that a system's hourly demand is projected to exceed available generating capacity.[5] A report prepared by the Energy Systems Integration Group (ESIG) additionally suggests that it is important for system operators to move beyond averages in assessing resource adequacy by also evaluating the full distribution of events to capture those low-probability, high-impact events that can prove quite costly.[6] E3 itself measured the reliability results of the various market designs studied using all three reliability metrics.[7]

APA and ACP suggest the Commission consider the use of more refined metrics (not just a single standard like LOLE) to identify system needs more granularly before selecting one or more reliability standards for the ERCOT Region. Then, the Commission can make a well informed and precisely-tailored choice of reliability mechanism to encourage development of the resources needed to meet those standards based upon a non-discriminatory assessment of the reliability contributions of those resources.

B. Questions related to the Performance Credit Mechanism (PCM)

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

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[4] Redefining Resource Adequacy Task Force 2021, *Redefining Resource Adequacy for Modern Power Systems*, Reston VA: Energy Systems integration Group, p. 10 (emphasis added).
[5] North American Electric Reliability Council 2021 Long-Term Reliability Assessment at 21-22 https://www.nerc.com/pa/RAPA/Reliability%20Assessments%20DL/NERC LTRA 2021.pdf.
[6] Redefining Resource Adequacy Task Force. 2021. *Redefining Resource Adequacy for Modern Power Systems* at 12-13. Reston VA: Energy Systems integration Group at 12-13.
[7] ESIG at 53, Table 18.

The lack of prior precedent for the PCM increases risk and undermines market certainty critical to new investment. As E3 notes in its analysis, "[a] PCM mechanism has not been implemented in any electricity market in the world to-date."[8] While this alone does not prevent the adoption of a novel market construct, E3 notes that "[i]mplementing a design that has been successfully implemented in other jurisdictions provides more confidence that the implementation will deliver as expected."[9] As E3's qualitative assessment of various market design options indicates, the PCM is among the most highly complex designs to implement administratively requiring various complex analytical tasks and the development of *de novo* tariff rules without any applicable precedent from other markets.

As a result, E3's assessment is that the PCM will require a long implementation timeline of 2-4 years to implement with several years to implement market rules and several more for the market to respond.[10] During the development of these centrally administered processes, there will be significant uncertainty in the market that may well undercut the potential positive impacts of various Phase One reforms implemented by the commission that have injected new revenue more often into the market. Given the rapid evolution of the ERCOT market, it seems entirely possible that the issues confronting the market will be quite different than those of today by the time that the PCM could feasibly be implemented.

It is unlikely that the PCM will incentivize generator performance, retention, and new market entry. The PCM does not incentivize generator performance but availability. Despite its name, the PCM does not incentivize generator performance. Performance would imply providing energy to the market whereas the PCM awards credits to generators based on whether they make a real-time offer into the market during one of the low reserve hours that is identified after the fact by ERCOT. This market design fails to reward generators based on the actual performance of all resources. It also fails to recognize that there is reliability value in hours adjacent to the hours selected by ERCOT on a post-hoc basis. E3 acknowledges that compensating resources for their availability in the 30 tightest hours "may not be completely

[8] E3 at 91, Table 46.
[9] *Id.*
[10] *Id.* at 82-83.

aligned with the hours that drive system reliability requirements."[11] E3 also observes that the PCM may incentivize strategic bidding behavior by offering at prices where they are unlikely to be dispatched, stating, "[i]t is possible that some resources may change their bidding behavior to increase their availability during the 30 hours (for example: a battery increasing its bid price to avoid discharge and increasing its ability to offer in more hours)."[12]

While the PCM may incentivize retention of existing generation, it is unlikely to produce new investment. By carving off $5.7 billion annually from the energy and ancillary services markets for a capacity market construct designed to benefit primarily thermal generators, it is possible that the PCM would pad the revenues of existing thermal resources, thereby retaining them in the market. It is less clear that the PCM will provide sufficiently stable price signals to incentivize new investment. While the PCM ensures that there will be 30 hours (or some other number) that will deliver significant revenue each year, it is quite difficult to forecast so that generators can ensure that they will be available during those hours to receive that revenue. E3 has acknowledged that the hours of lowest incremental reserves may be due to thermal outages,[13] which in the case of forced outages are random and difficult to predict although they can be quite significant. Or a generator could be on planned maintenance outage during the shoulder season during hours of low operating reserves and fail to receive the performance credit. Moreover, these hours may be tightly clustered so if a generator fails to forecast correctly, they may miss a significant portion of the revenue available for that year. The casino nature of these risks renders revenue projections far more unstable than, say, adjustments to the ORDC that are a fundamental feature of the energy market. It is, therefore, unclear whether the price signals provided by the PCM would support new entry.[14]

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[11] *Id.* at 79.
[12] *Id.* at 80.
[13] E3 Technical Conference, December 2, 2022. ("...hours of highest reliability risk are defined as the hours with lowest incremental available operating reserves. Some examples of when peak net load might not be aligned with those hours would be for example, in time periods where there are large quantities of thermal outages. Large quantities of thermal outages reduce the availability of operating reserves. But thermal outages are not typically included in the classic calculation of net load and so they wouldn't be reflected in that.").
[14] It should be noted that testimony by the IMM before both the House and Senate committees has indicated that the IMM believes that the E3 assessment overstates resource retirements and failed to properly model the ORDC changes, which undermines the conclusions drawn in the E3 report regarding resource adequacy and LOLE. *See, e.g., Testimony of Independent Market Monitor Carrie Bivens, Potomac Economics, before the Senate Committee*

It is not clear that the PCM aligns with legislative intent or will enhance the ability of the ERCOT market to address extreme weather or provide additional operational flexibility in real-time. Section 39.151(b), Utilities Code, directs the Commission, in relevant part, to require ERCOT to determine the region's reliability needs, and "to determine the quantity and characteristics of ancillary or reliability services necessary" to meet those needs under specified conditions, and to "develop [] appropriate qualification and performance requirements," size those products appropriately, and competitively procure them. The plain language of the statute strongly suggests that the legislature intended that market needs be met through ancillary or reliability services rather than via a redesign of the wholesale market that reallocates $5.7 billion annually out of the energy and ancillary service markets. Recent legislative oversight hearings and other communications from the legislature[15] suggest, at a minimum, that there is a lack of agreement on whether the PCM complies with legislative intent.

While APA applauds the Commission for the steps that it has taken in Phase One to enhance resource availability including creating weatherization requirements and a firm fuel product, it must be acknowledged that significant risk remains around fuel security for the bulk of the ERCOT thermal fleet that NERC and others have identified as a significant risk.[16] According to

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on Business & Commerce, November 17, 2022. The IMM has further noted that the Phase One changes to the scarcity pricing mechanism have injected significant new revenues into the market that have primarily gone to thermal generators. The IMM testified:

> ...the commission has already taken significant steps with Phase One of the market redesign and the results of those changes have not yet had time to come to fruition. The energy only market can and does result in the planning reserve for margin reliability standard that the commission is considering adopting.

Id. The IMM's testimony strongly suggests that the IMM does not believe that there is a resource adequacy issue but rather an operational issue better address via targeted ancillary services such as the uncertainty product proposed by the IMM.

[15] Letter from Senate Committee on Business & Commerce, December 1, 2022.

[16] North American Electric Reliability Council. November 2022. *2022-2023 Winter Reliability Assessment* at 4. (While noting improvements related to weatherization and critical infrastructure, NERC states regarding ERCOT, "[t]he risk of a significant number of generator forced outages in extreme and prolonged cold temperatures continues to threaten reliability where generators and fuel supply infrastructure are not designed or retrofitted for such conditions."); Astrapé Consulting. 12.7.2022. *Effective Load Carrying Capability: Final Study* at 53. ("When fuel availability restrictions are taken into account, the winter ELCC decreases even further, as shown in Table 12. For example, the last row of the table shows that by layering in fuel outages on top of the 2011 and 2021 cold weather assumptions, the ELCC of the thermal fleet can decrease another 10.3% down to 67.6%.").

E3's analysis, the PCM is not well-suited to address extreme weather because "…accrediting resources based on their actual performance each year poses the [sic] overcompensate resources during mild years, ***even if they are not able to reliably perform during extreme weather events***."[17] Nor is it clear that the PCM is the best available mechanism to address operational flexibility needs in real-time. A targeted ancillary service that pays resources for real-time performance when dispatched as opposed to availability and sized to address variability due to load forecast errors, thermal outages, or variable output from renewable generators would seem to be a more targeted, effective, and cost-efficient mechanisms to address operational flexibility than the PCM.

Costs to consumers from the PCM are highly uncertain but will assuredly be higher if renewable resources are excluded from participation in a discriminatory manner. Given the significant uncertainties around setting the administratively determine demand curve, market rules, the operation of the forward market for credits, and potential implications for risk and costs for load-serving entities (LSEs), it is difficult to assess the impact of the PCM proposal on consumer costs with any degree of certainty.

What is clear from E3's analysis that excluding renewable resources from eligibility to be awarded credits when they offer into the market on the same basis as other resources will increase costs. E3's analysis notes that while not awarding performance credits to renewable resources would save money in the short-run, these savings would be erased over time by the deployment of more costly resources.[18] In the technical presentation on the E3 report, E3 representatives stated, "I think it would be our expectation that a technology neutral approach would yield lower costs and those dynamics might take, you know, a longer run time horizon to manifest but that would be our expectation…"[19] E3 further notes, "[i]f the PCM design were to be implemented in a non-technology-neutral manner, e.g., by excluding the cost/compensation of resources such as wind or solar, this would diminish its effectiveness as a competitive market

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[17] E3 at 87, footnote omitted (emphasis supplied).
[18] *Id.* at 74.
[19] E3 Technical Conference, December 2, 2022.

mechanism."[20] Discriminatory treatment of renewable resources fails basic principles of sound market design around technology neutrality and recognizing the reliability contributions of all resources. It also sacrifices affordability in favor of diverting additional revenues to more costly resources even when not required to deliver reliability.

APA and ACP believe that any market design concept should be technology neutral. Regardless of the type, if a generator can perform during times of need or otherwise perform as required, that generator should be compensated equally under any proposed framework. Further, any proposal should use longer term forecasts performed on a regional or sub-regional basis. The longer term forecast will provide more information for generators looking for investment signals. Finally, the importance of a robust transmission system cannot be overstated. It is key to attracting new investment where it is needed most. Effective and forward-looking transmission planning processes and implementation plans are necessary for a reliable and resilient grid in order to move generation to load efficiently and reliably.

C. Questions related to Operational Risks
D.

Question 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?

Question 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?

As designed and studied by E3, the LSERO, FRM, PCM, and BRS are all focused on the "periods of highest reliability risk, measured as the hours of lowest incremental available operating reserves." The authors assert, without evidence, "These hours are typically, but not exclusively, aligned with 'peak net load.'"[21] Without explanation, E3 does not use ERCOT's definition of net load – total system demand minus wind and solar output. Instead, E3 also subtracts the contribution of energy storage from system demand which will tend to overstate the net load to be served by non-renewable generation. This is an inappropriate study

[20] E3 at 79, n. 46.
[21] E3, p. 15.

assumption given the prevalence of co-located solar and battery storage units on the ERCOT system and in the interconnection queue. More importantly, historical data does not support E3's assertion of correlation between high net load hours and hours of low operating reserves. Figures 1 and 2 below plot the 50 hours of highest net load and the 50 hours of lowest operating reserves in calendar years 2020 and 2022. In each of those two years, only 12 hours were in both the top 50 high net load hours and the bottom 50 low operating reserves hours

Fig. 1. **ERCOT top 50 highest net load hours and bottom 50 operating reserves hours (2022)**

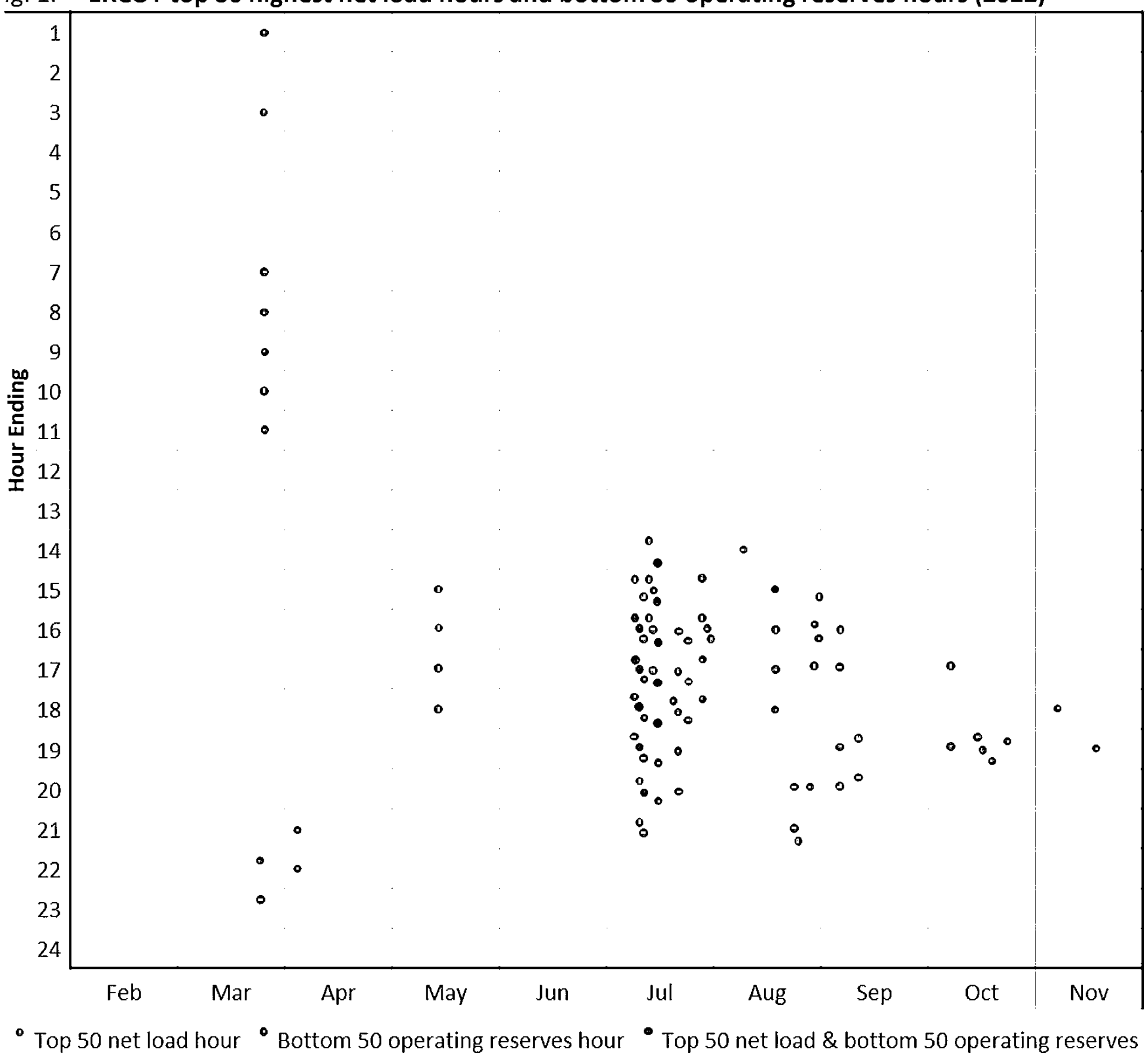
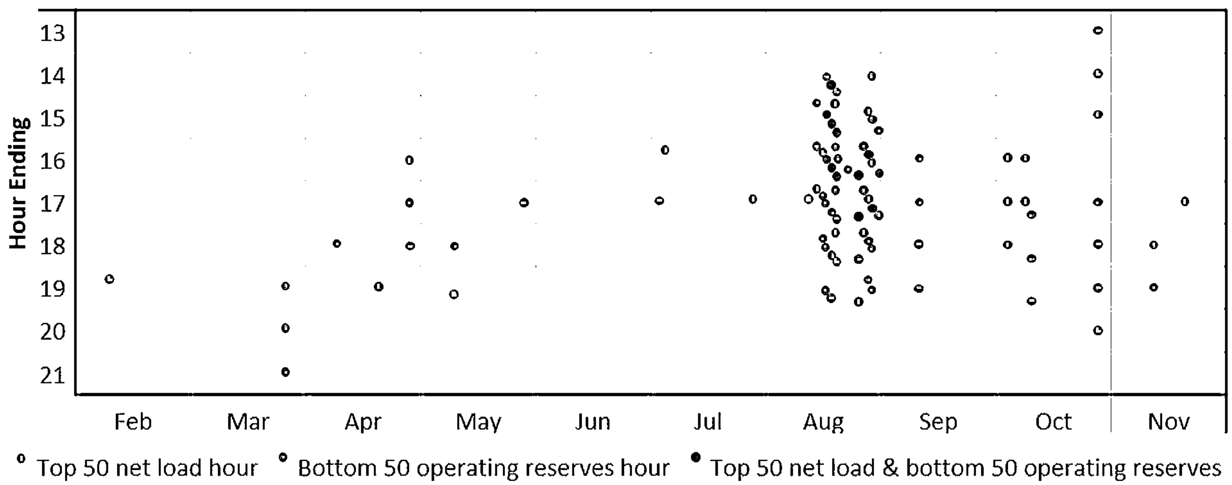


Fig. 2. **ERCOT top 50 highest net load hours and bottom 50 operating reserves hours (2020)**



Data from 2021 is excluded from this analysis due to the difficulties of dealing with the anomalous impacts of Winter Storm Uri. However, it is worth noting that the bottom 50 hours of lowest operating reserves in 2021 were all contained within that one-week event. This should guide the Commission to use caution about piling too much risk or reward into any small number of hours per year as it could magnify the outsized gains or losses incurred by market participants during any future black swan event. If the Commission decides it should tether the reliability mechanism to targeted hours, it should use a larger, not smaller, number of hours.

Hours of low operating reserves occur for several reasons that have nothing to do with the level of net load in ERCOT – planned and forced outages of thermal units, generation trapped behind transmission constraints, the magnitude of error in ERCOT's forecasts for weather, load, and renewable generation production – all of which feed into ERCOT's unit commitment process and system positioning activities.

This begs the question of what problem the Commission is trying to solve with one or more of these proposed reliability mechanisms, especially when one considers the numerous market mechanisms and other programs which target hours of low operating reserves such as the procurement of ancillary services, the unit commitment process, the 4CP transmission cost allocation methodology, the Operating Reserve Demand Curve, and Emergency Response Service. Before choosing a reliability mechanism, the Commission should take time to carefully study how adding a new market mechanism targeting the same hours as existing market mechanisms will affect the efficacy of those mechanisms and whether any unintended consequences might be introduced to the market, including dilution of value to ratepayers and excessive costs borne by ratepayers due to overlapping mechanisms.

If E3 intended its selected 30 hours to address the highest net load hours, the data shows it selected the wrong hours. If E3 intended its selected 30 hours to address the lowest operating reserve hours, then the prevalence of such hours in the shoulder months should give pause to the thermal generators who use those months for maintenance outages and to ERCOT and the transmission utilities who would be forced to manage generators adding reliability mechanism reward and penalty calculations into their outage scheduling decisions, which will only further complicate maintenance outage seasons that are already too short and crowded.

Finally, it is worth noting that the hours of concern today are not the same as yesterday and likely to be still different tomorrow. As the generation fleet evolves, as energy storage increases market penetration, as demand-side flexibility and market participation increases, new challenges will arise in new hours. Without yet having defined the reliability standard(s) for the bulk electricity system, it is premature at this point to dwell too deeply on whether or not to tie a reliability mechanism to specific hours.

D. Questions related to bridge products

*Question 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?
Question 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?

<u>Question 11</u>. ***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.***

Given that under the most optimistic estimates implementation of fundamental changes to ERCOT's market design would require 2-4 years according to E3's own estimates, while engendering continued market uncertainty that would undermine near-term investment, APA does believe that additional steps to meet demonstrated system needs should be adopted.

The IMM has recently reported that Phase I changes and conservative operations have already injected sufficient new revenues into the market:

> Regarding our cost procurement of additional non-spinning reserve services, we've estimated that between August of 2021 and July of 2022, this has cost between **$800 million and a billion dollars.** Next regarding the Commission's change to the scarcity pricing mechanism, as of January 1, this year, we calculate the impact on energy costs of that change to be approximately **$1.6 billion dollars** through October 31st. For context, the total impact of the operating reserve demand curve adder on energy costs for the same time period was **$2.8 billion.** And that figure represents about 10% of the total real-time energy market value of approximately $28 billion dollars year to date. So as you can see, the commission has already taken significant steps with Phase One of the market redesign, and the results of those changes have not yet had time to come to fruition. **The energy-only market can and does result in the planning reserve for margin reliability standard that the Commission is considering adopting.**[22]

As the IMM noted at the Senate Business & Commerce hearing on November 17, 2022, the bulk of these additional revenues go to thermal generators.

To the extent that these significant new revenues are deemed insufficient to attract or retain adequate levels of dispatchable generation to maintain reliability, the Commission should consider further evaluation and potential adoption of a new ancillary service product to address near real-time operational uncertainty along the lines proposed by the IMM[23] and the

[22] Testimony of Independent Market Monitor Carrie Bivens, Senate Business and Commerce Committee, November 17, 2022.
[23] Potomac Economics, 2021 ERCOT State of the Market Report.

coalition for Dispatchable Reliability Reserve Service (The Coalition).[24] For reasons more fully documented in the filing by The Coalition, such a product would address near-term operational uncertainty in a manner that is more economically efficient than relying on procuring artificially high levels of reserves or reliance on out-of-market actions. Creation of such a product would provide additional revenues for slower starting resources with longer durations and therefore allow the resource qualifications for the current non-spinning reserves and ERCOT Contingency Reserves Service (ECRS) to be adjusted to compensate faster-responding resources, thereby providing a robust portfolio of services to address real-time operational uncertainty.

To enhance resource availability during extreme weather, the Commission could additionally consider the adoption of either a modified version of the Backstop Reliability Service (BRS) that is closer to the version proposed initially by Commissioner Cobos than the version modeled by E3 or a modified Reliability Must Run (RMR) mechanism to temporarily retain thermal units at risk of retirement. The BRS can further “top up” effective capacity during the times the grid needs it most. Any capacity held out of market by the BRS mechanism can be replaced by new generation investment enabled through changes to the ORDC. As discussed further below, while Phase I reforms to the ORDC mechanism are helpful to incentivize new capacity, the PCM mechanism risks creating a condition in which ORDC events are less likely to be triggered, negatively impacting the effectiveness of Phase I reforms. The “Low Cost of Retention” scenario in the E3 analysis notes that the current market “has a surplus of resources that need to be retained to achieve target reliability as opposed to incenting new dispatchable resources into the system,” and that these resources could be retained at significantly less cost than CONE as required for new resources.[25]

E3’s analysis of the BRS found that these resources would operate relatively infrequently (~6 hours/year on average) and only when prices are at the cap to avoid dampening market

[24] Comments of The Coalition for Dispatchable Reliability Service, https://interchange.puc.texas.gov/Documents/52373_384_1258736.PDF.
[25] E3 at 72.

signals for new investment.[26] E3 found that "the BRS yields expected benefits in the form of improved reliability, specifically, reduced Expected Unserved Energy. This benefit is not included in the quantified benefits, meaning that the quantified benefits are conservative."[27] E3 additionally notes, "[w]hile the BRS mechanism could be configured to improve system performance during extreme weather events if BRS resources were required to have firm fuel and be capable of generating during fuel disruption events, this requirement was not included in the design developed by PUCT for this study."[28] To enhance resource availability, any such product should require fuel security and penalties for non-performance as required by SB 3.

Further specifics regarding how these mechanisms would work should be determined in consultation with ERCOT and stakeholders. Given the relatively short timeframe in which ERCOT was able to implement the new Firm Fuel Service, it should be possible to implement these solutions, if needed, in a reasonable period of time.

E. Questions related to Dispatchable Energy Credit (DEC):

Question 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?*

The E3 report modeled a DEC design that differed dramatically from that initially proposed by Commission McAdams in his November 17, 2021, memo filed in Project No. 52373 in several important ways. First, Commissioner McAdams proposed eligibility requirements that included the ability to "ramp to full nameplate capacity within 5 minutes or less and have a net facility specification heat rate less than or equal to 8,000 Btu/kWh, or a battery that can discharge for at least 2 hours."[29] The E3 report, in contrast, assumed a slightly less efficient heat rate of 9,000

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[26] E3 at 61.
[27] E3 at 26.
[28] E3 at 87.
[29] Commissioner McAdams Memorandum, Project No . 52373 , Item No . 21 - Review of Wholesale Electric Market Design (November 17, 2021) available at https://interchange.puc.texas.gov/Documents/52373_250_1168223.PDF.

Btu/kWh and, more importantly, a requirement that DEC-eligible resources be dispatchable for a minimum duration of 48 hours.[30]

Second, Commissioner McAdams proposed that each LSE receive an obligation to procure a quantity of DECs equal to its share of system demand during key peak seasonal intervals. E3 on the other hand assumed that each LSE would procure DECs equivalent to 2% of their annual load.[31] According to E3, this requirement is approximately based on the total quantity of DECs that could be produced by the incremental quantity of dispatchable resources that would be procured by the LSERO, FRM, PCM, or BRS market designs, relative to the Energy-Only market design.

The Commission should revisit these assumptions and conduct further analysis on the DEC design more in line with that initially proposed by Commission McAdams. First, the Commission should reconsider the 48-hour runtime requirement. This requirement would exclude from participation all energy storage resources that are currently in ERCOT or are in the process of development and have signed generation interconnection agreements. In addition, this requirement ignores facts relied on by ERCOT staff when considering potential duration requirements for resources providing ERCOT Contingency Reserve Service (ECRS) and Non-Spin Reserve Service. When ERCOT analyzed the potential duration needs for resources providing ECRS, ERCOT determined that 99% or more of the events for which it would deploy ECRS have a duration of less than two hours, and 100% of the events were for a duration of less than four hours.[32] There is no factual basis to impose a 48-hour duration requirement on these resources. Energy storage resources currently operational in ERCOT, the vast majority of which have a name-plate duration of less than 2 hours, already have proven themselves to be valuable resources to provide ancillary services and that also help smooth price volatility by consuming power during times of overproduction and injecting power during times of scarcity. In a presentation to ERCOT's Supply Analysis Working Group on December 13, 2022, ERCOT

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[30] E3 Report, p. 113.

[31] E3 Report, p. 115.

[32] ERCOT Staff, *NPRR 1096 Sustained Duration for ECRS and Non-Spin Ancillary Services*, Performance, Disturbance, Compliance Working Group (Nov. 12, 2021) at 6 (available at https://www.ercot.com/files/docs/2021/11/11/NPRR_1096_Update_11042021_v9.pptx).

Staff showed that battery energy storage resources that already are deployed in ERCOT provided an average real-time contribution of 947 MW to Physical Responsive Capability (PRC) during the hour of tightest reserves on July 13, 2022.[33] That contribution increased to 1 GW by the end of August 2022. Under ERCOT's current market design, developers have little incentive to build longer duration batteries. The market signals have encouraged the development of batteries to address short duration needs of the grid. However, with improvements in technology coupled with the market signals ERCOT has created to encourage longer duration batteries, those are being brought to the market today, with more in development and construction.[34] Because the DEC design is market-based, the value of DECs would gradually fall as more batteries and other DEC-compliant resources come online.

Second, the quantity of DECs should not be based on gross load or based on the outcomes of other market designs that E3 modeled. In his original proposal, Commission McAdams proposed that the target amount of DEC-compliant resources should be based on ERCOT's growth in load. This recognized that, if ERCOT is already tight on capacity and needs everything it has, adding DEC-compliant generation at the same rate as the growth of load would avoid pushing less efficient generation out of the market since we would still need all resources we have. As an alternative, the volume of DECs to be procured could be based on incenting the development of a specified amount of DEC-compliant resources, such as the goals provided in Utilities Code §39.904(a).

Finally, if the Commission wanted to use the DEC proposal to encourage the development of other new technology, the Commission could modify the requirements for DEC-compliant dispatchable generation to be any new dispatchable generation and allow the competitive market to determine which are the best resources to bring to the market. This modification would allow new technology such as small modular nuclear reactors to qualify as well.

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33 Pete Warnken, *November CDR and Winter SARA Review*, Supply Analysis Working Group (Dec. 13, 2022) at 6 (available at https://www.ercot.com/files/docs/2022/12/12/3__SAWG_CDR_and_SARA_Review_12-13-2022_.pptx).

6 *See, e.g.*, ERCOT Co-Located_Battery_Identifiecation_Report_November_2022 (12/7/2022) at worksheet labeled "Battery RFI Charts" (available at https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=881468605).

APA believes that modifying the DEC proposal as described above would enhance reliability without the price-suppressive effects E3 assumed would occur.

CONCLUSION

The Advanced Power Alliance and American Clean Power Association appreciate the opportunity to provide comments in this project. We urge the Commission to conduct further evaluation of market design proposals, including a review of the IMM suggested Uncertainty Product and that any solutions implemented be technology neutral and based on first principles of market design-namely that any market design reforms should be non-discriminatory, transparent and should enable easy market entry and exit so that all resource types and market participants can effectively evaluate and respond to market signals and thereby achieve an optimal resource mix at least cost. A recent study performed by Dr. Joshua Rhodes demonstrates that in the first eight months of 2022, renewables reduced ERCOT wholesale electricity prices by approximately $7.4 B and are on track for to exceed $11 B in cost savings by the end of the year. This savings helps to offset higher market costs resulting from recent increases to consumer prices resulting from higher fuel costs, conservative operations, Phase I changes implemented, securitization adders and extraordinarily high congestion costs.

Respectfully submitted,

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PROJECT 54335

EXECUTIVE SUMMARY OF THE ADVANCED POWER ALLIANCE AND AMERICAN CLEAN POWER ASSOCIATION COMMENTS

- E3 does not recommend the PCM and states in their report that "implementation of the PCM entails significant risk because of its novelty."
- APA and ACP share the view held by many stakeholders that the E3 analysis was deeply flawed, and these flaws undermine E3's ultimate conclusions with respect to the various market designs.
- There is broad consensus for conducting further evaluation of market design proposals, including a review of the IMM suggested Uncertainty Product.
- We agree with the Texas Senate and Business Commerce Committee directive that asks the Commission to "define the reliability goals for the ERCOT Region prior to moving forward with any significant market redesign."
- APA and ACP urge that any solutions be technology neutral and based on first principles of market design-namely that any market design reforms should be non-discriminatory, transparent and should enable easy market entry and exit so that all resource types and market participants can effectively evaluate and respond to market signals and thereby achieve an optimal resource mix at least cost.
- Costs to Texas consumers from the PCM are highly uncertain but will assuredly be higher particularly if renewable resources are excluded from participation in a discriminatory manner.
- A recent study performed by Dr. Joshua Rhodes demonstrates that in the first eight months of 2022, renewables reduced ERCOT wholesale electricity prices by approximately $7.4 B and are on track for to exceed $11 B in cost savings by the end of the year. This savings helps to offset higher market costs resulting from recent increases to consumer prices resulting from higher fuel costs, conservative operations, Phase I changes implemented, securitization adders and extraordinarily high congestion costs.
- APA and ACP urge the Commission to adopt a new Dispatchable Reliability Reserve Service (DRRS), built on the Uncertainty Product advocated by the ERCOT IMM, as the best mechanism to ensure the supply of reliable and affordable electricity to support continued economic growth in Texas.