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Received - 2022-12-09 03:23:20 PM
Control Number - 54335
ItemNumber - 31

PROJECT NO. 54335

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

PROBLEMS WITH THE E3 "ASSESSMENT OF MARKET REFORM OPTIONS TO ENHANCE RELIABILITY OF THE ERCOT SYSTEM" REPORT FOR THE PUBLIC UTILITY COMMISSION OF TEXAS, NOVEMBER 2022 AND COMMENTS ON THE PUCT QUESTIONS OF NOVEMBER 10, 2022

Comes now Alison Silverstein of Alison Silverstein Consulting, an independent energy analyst, to offer feedback on the report prepared by Energy and Environmental Economics, Inc., (E3) for the Public Utility Commission of Texas market reform effort. The E3 report contains significant analytical and methodological flaws that bias its findings on reliability policy options, and it would be a grave error for the Commission to base ERCOT market reform on the conclusions in this report.

The stakes to the Texas economy and Texans' well-being from ERCOT market reform are huge. The cost and reliability of electricity in Texas will affect the health of our state economy, which exceeds $2 trillion in gross state product, the ninth largest economy in the world. We produce and consume more energy and more electricity than any other state, with winter and summer peak electric demand driven disproportionately by residential heating and cooling. The average Texas electric bill today is $181/month [Energysage.com, 12/4/22] with an average rate of 13-14 cents/kWh. Statewide, Texas has a poverty rate of 14.2% [welfareinfo.org], but as electricity and natural gas prices rise, over 40% of Texans are sacrificing food, medications and other necessities and consuming less energy in order to pay their energy bills. Twenty-six million Texans live in ERCOT; as many as ten million of them were out of power and/or water for extended periods during Winter Storm Uri in 2021, and hundreds of Texans died from that extended grid failure.

This context matters because while we must improve ERCOT power system reliability, we cannot do so at any cost, and we cannot do so using poorly understood, poorly-analyzed, or unproven market mechanisms to address unclear problem definitions and goals. If the Commission makes a bad decision on ERCOT market reform due to haste, erroneous problem definition, sloppy analysis, or misguided rationalizations, all Texans will bear the consequences for years through higher electric costs, lower reliability, and a slower economy, and millions of lower income Texans will suffer degraded health and comfort as they sacrifice to pay their electric bills.

The PUCT has not spent enough time defining the grid reliability problem to be solved, even though problem definition is the necessary first step to finding solutions. The PUCT, ERCOT and most Texans face three problems:

1) A <u>resource and energy adequacy problem</u> of how to meet extreme events and tail risks created by combinations of high demand, extreme weather, high thermal plant outages and low renewables production;
2) An <u>operational flexibility problem</u> of how to meet peak needs in non-peak shoulder seasons, on cold winter mornings as load rises quickly, and ramping needs when sunset declines or renewable production falls short of operating forecasts;
3) An <u>energy affordability problem</u>, because electric retail bills are already very high due to high fossil fuel costs, increasing costs from ERCOT's conservative operating practices, and Winter Storm Uri cost recovery fees.

A set of good market reform policies will reflect careful consideration of:

- Whether the proposed reforms are targeted to one or more of the problems above;
- Whether the reforms will actually produce additional, useful infrastructure and resources to address the targeted reliability problem or primarily enriches the owners of existing generation;
- Whether the costs of new resources are commensurate with the reliability benefits promised;

- Whether specific policies and their unintended consequences increase the risk and volatility of electricity costs and reliability associated with fossil fuel prices and aging power plants;
- Whether the reforms raise overall electric prices and burdens on the Texans who are already struggling economically; and,
- The relative cost-effectiveness, risk mitigation, solution timing and equity impacts between multiple proposals.

The Commission, the Texas Legislature, and the people of Texas deserve thoughtful, deliberate analysis of all available ERCOT reliability improvement options using the best analyses available. The E3 report prepared for the Commission is too deeply flawed to be trusted to guide reliability and market decisions of this import. Many of those flaws misrepresent or mislead ERCOT's reliability risk while overstating the reliability benefits and understating the costs of the market reform options studied. The Commission should not use this report as the basis for upcoming ERCOT market reform decisions – the consequences of a poor decision are too high and Texans deserve better. Since Chairman Lake has assured the Legislature that ERCOT market solutions will not be implemented until after the 2023 legislative session, there is time to conduct a more credible analysis that uses better analytical assumptions (including 2021 and 2022 extreme weather conditions) to evaluate a wider set of reliability-affecting market reforms.

Does or doesn't ERCOT have a reliability problem? Hard to tell from this report…

E3 uses inappropriate metrics that yield misleading answers

The E3 study refers broadly to system reliability as, "frequency, duration and magnitude of load shedding events." E3 reports its reliability findings principally in terms of loss of load expectation (LOLE) relative to the common industry target of LOLE = 0.1 days/year and the Commission appears to support that goal. [PUCT cover memo to E3 report, p. 2] LOLE represents "the total number of days per year that the system is expected to have loss of load of any size or duration," because the grid operator doesn't have enough supply to produce all the electricity customers demand.

The E3 report indicates that ERCOT does not have a reliability problem now, calculating that LOLE = 0.03 in ERCOT today. [E3, Table 58, p.126] This nugget, buried in the back of the report, means that ERCOT's reliability is already much better than the goal of LOLE = 0.1 (or 1 day in ten years with an outage event). This view of a reliable system is supported by the ERCOT estimate that we will have a generous 37% planning reserve margin of supply over demand for the coming winter and that the ERCOT grid operator anticipates no reliability concerns under normal weather conditions. [ERCOT Winter 2022 CDR, p. 18, and CEO Vegas comments]

If we already have high reserve margins and reliability above target levels in ERCOT today, then why does ERCOT need a new reliability mechanism to bring additional dispatchable generation online? The answer is that the E3 report is focused on solving the wrong problem and E3's LOLE metric and study methodology are flawed. We know that ERCOT is not highly reliable today – the ERCOT grid has operated on the edge of outages repeatedly during the heat waves of May and July 2022 due to combinations of high demand, low wind and high thermal outages, as confirmed in comments by Commission Chairman Lake on November 29, 2022 and repeated in subsequent public statements. ERCOT experienced tight conditions as recently as the evening of November 26, 2022, when demand was unremarkable but planned and forced outages were high. The North American Electric Reliability Corporation (NERC) 2022 Winter Reliability Assessment, Federal Energy Regulatory Commission's (FERC) 2022-2023 Winter Assessment and ERCOT's own 2022-23 Winter Assessment warn that although power plant winterization is a meaningful improvement, ERCOT remains at risk of deep supply shortfalls this winter if we experience another severe winter cold event with extremely high peak loads, high thermal outages and low wind generation. It remains unproven whether Texas' natural gas production and delivery system has been adequately winterized to maintain fuel security through future extreme cold weather events.

E3's calculation that ERCOT is highly reliable this year is disproven by these actual reliability assessments and warnings. LOLE and reserve margins are insufficient metrics to represent current and upcoming real reliability and operations in ERCOT as demand grows and the resource mix evolves. NERC and other industry experts [see, e.g., Stenclik et al., 2021] now recognize that sound reliability and resource adequacy analysis must go beyond LOLE to investigate not just averages but the spectrum of reliability and resilience tail events using a broad suite of reliability dimensions including:

- Energy as well as capacity adequacy,
- Loss of Load Expectation (LOLE),
- Loss of Load Events (LOLEv, the number of events per year when the system could lose load),
- Loss of Load Hours (the number of hours per year when the system could lose load),
- The duration of Loss of Load Events (whether 5 minutes, 5 hours or 5 days),
- Expected Unserved Energy (the total quantity of energy per year when the system may not be able to serve due to insufficient resources), and
- The number of customers affected by LOLEv.

The PUC should address well-defined problems

The PUCT has been directed to adopt measures to prevent future extreme weather grid disasters (the resource and energy adequacy problem). The PUCT and E3 interpret this as requiring enough dispatchable generation resources to ensure reliability during extreme weather conditions with low non-dispatchable power production, to prevent prolonged rotating outages due to high demand and low supply. ERCOT load is growing quickly. After a decade when Texas population grew by over 16%, winter loads could have reached 82,000 MW during Winter

Storm Uri if not for the extended outages [Dessler & Lee, TAMU, 2022]. Extended heat waves drove summer loads to successive peaks in 2022, exceeding 80,000 MW in July 2022. [ERCOT, p.3] So it is not unreasonable for the E3 report to focus on the goal of building enough new dispatchable resources to cover peak load and drive down LOLE.

But E3's analysis routinely refers to "hours of highest reliability risk, measured as the hours of lowest incremental operating reserves," and asserts with limited evidence that those hours are typically but not exclusively aligned with "peak net load."[1] [E3 pp. 14-15] Actual shortfalls on dates like May 13 and November 26, 2022, were due to high planned and forced thermal plant outages rather than extraordinary peak loads or low renewable generation. These and Chairman Lake's references to "blue sky" reliability problems are different versions of the operational flexibility problem rather than a lack of dispatchable resource capacity per se. The operational flexibility problem requires a different set of metrics and solutions than the resource and energy adequacy problem.

To date neither the PUCT nor the E3 study have directly addressed the reality of Texas' energy affordability problem. If anything, suggestions from Chairman Lake and others to solve the resource adequacy problem by excluding PCM payments to wind and solar resources "could result in smaller wind and solar buildout … which would have the effect of increasing energy

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1 To date there is no public information available to indicate whether E3 or ERCOT have conducted any back-cast or review of recent years (e.g., 2019 through 2022) to identify the hours of high reliability risk. Such an analysis would look at whether actual operating data show any correlation or causal relationships and identify correlations if any between the times of season and year when:

- incremental operating reserves were lowest,
- net peak load was highest,
- net peak load less storage (which E3 calls peak net load) was highest,
- high levels of thermal generation outages (which the ERCOT IMM identifies as one of four major operational uncertainties),
- low levels of wind or solar production relative to ERCOT's forecasts (two more major operational uncertainties)
- significant ERCOT under-forecasts of customer demand (the fourth major operational uncertainty).

prices" [E3 p. 74] over time. Such policies ignore the reality that Texas' extraordinary wind and solar resource development has reduced annual electricity costs by billions of dollars and buffered us from the high cost and volatility of natural gas and coal prices. [Rhodes, "The Impact of Renewables in ERCOT," October 2022] The growth of battery resources in ERCOT will facilitate the use of low-cost renewables to enhance both reliability and affordability.

E3 Study Methodology and Assumption Flaws

1) The E3 study doesn't adequately address the reliability challenges associated with more extreme weather and extreme load. It examines historic extreme weather events but excludes 2021 Uri winter event, 2022 heat waves and forward-looking extreme weather conditions that may have higher ferocity and frequency than the historic dataset.

Although a primary impetus for this market reform effort is to assure that the ERCOT region has enough resources to meet future weather-driven customer demands during extreme weather circumstances, the E3 study tests the ERCOT reliability proposals against only historical summer and winter peak load weather conditions between 1980 and 2019 [E3 pp. 34-38]. This weather set excludes Winter Storm Uri in 2021 and the summer heat waves of 2022, both of which pushed ERCOT operations to the breaking point. It excludes the Texas State Climatologist's finding that average Texas temperatures are rising steadily and winter precipitation events and flooding are getting worse. [Texas State Climatologist, 2021] As E3 acknowledges, "This study implicitly assumes that future weather conditions will have the same variability as observed across these 40 historical years. To the extent that future weather conditions are likely to differ significantly from historical conditions, ERCOT should consider incorporating these factors into future analysis and/or any implementation of market reforms." [E3 p. 34]

NERC's "2021 Long-Term Reliability Assessment" report explains, "Regulators and policymakers should review the scope of their resource adequacy requirements to ensure that they address risks of both energy and capacity shortfalls and consider both peak and non-peak demand hours. They should also consider … long-duration extreme weather events and potential generator fuel supply limitations."

By excluding consideration of the 2021 and 2022 actual extreme weather conditions and forward-looking conditions, the E3 study fails to provide useful information on its primary task – helping the ERCOT system remain reliable under future extreme weather conditions. Analyzing reliability mechanisms against only historic weather conditions is not a valid test of the ERCOT system's potential performance under more severe future weather conditions because it overstates reliability performance while understating the likely costs of keeping the system reliable in the face of harsher weather conditions.

2) The E3 study underestimates thermal generator outages and assumes perfect fuel supply despite Uri failures.

Generation forced outages and capacity derates are highly correlated with bad weather conditions, as recognized by NERC,[2] documented in FERC Docket No. AD21-13-000 on electric reliability and climate change, and by the Texas Legislature and Commission in requiring power plant and transmission weatherization. Extremely hot weather can limit transmission throughput and force thermal generator deratings; droughts can restrict thermal generator output; and extremely cold weather can reduce fuel supply availability and reduce or fully stop power plant

[2] E.g., "Wide-area and long duration extreme weather events driven by climate change threaten reliability when electricity demand is driven above forecasts and supplies are reduced. Diminished levels of flexible generation--fuel-assured, weatherized, and dispatchable resources--create vulnerabilities to energy shortfalls when extremely hot or cold weather settles over a wide area for extended duration….". [NERC, "Long Term Reliability Assessment, December 2021", p.6]

operation and output (as documented in the FERC-NERC 2021 Winter Storm Outage analysis and numerous NERC and PUCT reports).

The E3 report inflates thermal generator availability and their contribution to reliability under extreme cold conditions by assuming "unlimited access to fuel when needed," [E3 FN 32, p.56] and that the PUCT's new Phase 1 weatherization requirements will prevent any widespread, weather-driven generation failures or reductions. E3 ignores the reality that coal piles freeze and that recent Texas Railroad Commission and PUCT weatherization reforms cannot guarantee continuing natural gas production and delivery in freezing, icy weather, leaving the bulk of the thermal fleet exposed to vulnerable fuel supplies.[3] The assumption of perfect thermal fuel availability under adverse weather conditions ignores a major cause of ERCOT's Winter Storm Uri failures. This unrealistically inflates reliability outcomes and lowers costs for every market reform option evaluated.

E3 does not appear to incorporate the higher forced outages occurring now as aging power plants are pushed to higher sustained operating levels under ERCOT's Phase 1 "conservative" operations practices nor acknowledge higher thermal outage rates under very high summer temperatures. These forced outages are by definition unpredictable. And since ERCOT can now overrule generation and transmission maintenance scheduling plans, ERCOT's scheduling practices may be exacerbating forced outages and precluding generators from assuring their availability at the times they predict will be most needed and valuable.

[3] The Texas Railroad Commission's new gas system winterization rules do not require all in-state gas production, processing and delivery elements to winterize. It is impossible for Texas stakeholders to know which elements of the natural gas supply chain for power plants have been identified as critical and winterized because the supply chain map is confidential and not available for public review. The effectiveness of gas system preparations have not been tested to date because there has not been much cold weather since the RRC rules were finalized on August 30, 2022. The RRC's first round of facility inspections against initial rules proved under-whelming, with a February 2022 Houston Chronicle analysis finding that only 41% of the inspected sites had successfully tested and verified their weatherization equipment or procedures. There has been at least one recent compressor shutdown due to cold weather, at 34°F at a DCP booster station, on November 25, 2022.

3) By arbitrarily removing 11.5 GW (nearly 20% of the ERCOT thermal fleet) in three years, the E3 analysis fabricates extreme scarcity, poor reliability and high costs in the energy-only baseline case, then "fixes" it by adding in new generation.

E3 structured the energy-only market base case to remove 11,560 MW of natural gas and coal-fired thermal generation before 2026. [E3 p. 46-47 and Tables 14 & 15] This is done as an "equilibrium adjustment," intended to raise energy and ancillary service market prices up to the cost of new entry (CONE) for a gas-fired combustion turbine ($93.5/kW-year).[4] But energy market prices can only get that high if enough generation exits the market to create deep scarcity that drives energy prices up to or above the CONE level. Thus E3 creates scarcity by forcing 11,560 MW of existing generation to retire, "assumed to be split equally between coal and steam gas turbine units."

E3 documents the sequence of generation removals in Table 15 (below), showing that as each increment of generation is removed from current resources (the top line), ERCOT's 2026 estimated reliability level (LOLE) moves from current LOLE = 0.02 (notably better than target reliability of LOLE = 0.1 but different than the 0.03 E3 reports elsewhere) up to 0.08 (close to the LOLE target of 1.0) after 5,220 MW of generation have been retired. Then E3 continues removing additional generation until estimated natural gas generator revenues reach $93.5/kw-year, at which point 2026 reliability is pushed down to LOLE = 1.25. This LOLE is well above (worse than) the stated reliability target of LOLE = 1.0.

[4] E3 assumes that market revenues must exceed the $93.5/MWh CONE in 2026 to motivate construction of new gas turbines, and to prevent existing gas and coal plants from exiting the market.

Table 15. Results of Calibration Process Used to Attain Condition of Market Equilibrium

Total Equilibrium Adjustment (MW)	Natural Gas CT Net Revenues ($/kW-yr)	LOLE (days/year)
–	~0.0	0.02
(3,820)	4.7	0.04
(5,220)	8.8	0.08
(6,630)	14.7	0.14
(8,040)	25.0	0.25
(10,860)	72.3	0.91
(11,560)	**93.5**	**1.25** ← *Market Equilibrium*

By forcing generation out of the ERCOT fleet over a very short time period to raise gas turbine revenues to $93.5/kW-yr, E3 effectively breaks the ERCOT energy-only market and artificially drives the market baseline to higher energy prices, higher total costs, and poor reliability. Then they use the various reliability mechanisms to "fix" the ERCOT market's new poor baseline reliability, using each alternative to pay enough to lure new generators online to replace the generation that was forced out of the market. Compared to the fictitiously unreliable, costly Phase 1 energy-only baseline, the proposed reliability mechanisms can improve reliability with relatively low incremental cost impacts.

But E3's basic retirement assumptions are questionable if not wholly wrong. For comparison purposes, only 6,481 MW of coal, natural gas and other generation was retired in ERCOT over the period 2017 through 2021, during a period with low natural gas prices, growing renewables [EIA using Form 860 data] and relatively low, stable energy market prices. Over the past year the ERCOT-PUCT Phase 1 measures (particularly ORDC changes to increase scarcity revenues, more non-spinning reserves and reliability unit commitments) have significantly increased revenues to suppliers, so peaker gas plants this year are earning a net margin of about $140,000/kW-year [Biennial ERCOT Report on the Operating Reserve Demand Curve, 10/31/22, p. 15], well above CONE for a new gas combustion turbine. This makes existing generation much more lucrative today than in the past and reduces the odds that 11,560 MW would retire by 2026. New gas-fired generation has already come online in ERCOT over the past two years and nearly 3 GW more sits in the ERCOT interconnection queue today, attracted by existing market rules without the promise of additional reliability revenue streams.

E3 also overstates the amount of revenue an existing generator requires to remain online. E3 structures its equilibrium analysis with this logic: "If CT margins are lower than CONE, coal and gas steam turbine units are removed from the system." [E3 p. 31]. This is incorrect. The ERCOT Independent Market Monitor (IMM) stated in testimony before the Senate Business & Commerce Committee on November 17, 2022, that E3's assumptions overstate resource retirements because many existing generators are willing to continue operating with revenues below the cost of new entry (although they are certainly earning more than that today and can reasonably expect to earn more in the future). IMM reports show few years over the past decade when ERCOT combustion turbine net revenues consistently exceeded CONE, belying E3's expectation that CONE-level revenues are necessary going forward to retain dispatchable generation. [See e.g. the "2021 State of the Market Report", p.87] The IMM has testified that she believes that the need for an additional 5,630 MW of new dispatchable generation is overstated.

As a practical matter, reliability and resource planning certainty would benefit from policies that seek to retain as much of the generation now online as possible and create a managed path to retirement for older, less competitive plants. However rich the financial incentives created by either the current Phase 1 market enhancements or the new Phase 2 market reform policies, the gas-fired generation now in the ERCOT interconnection queue may not come online as quickly as a grid model predicts. If we actually need less than 5,630 of new gas-fired generation by the end of 2026, or if new builds are delayed, then implementation of E3-

modeled reliability measures could unnecessarily pay large profits to existing generators without delivering all the new dispatchable resources on the brisk schedule E3 predicts – in other words, we could pay much more to existing generators but get more scarcity and less reliability.

4) E3 modeled the ERCOT ORDC curve incorrectly, understating future energy-only market revenues and lowering the size of the baseline case incentives.

The ERCOT IMM has commented that E3 modeled the ERCOT ORDC inappropriately. During the Texas Senate Business & Commerce Committee hearing on November 17, 2022, the IMM stated in testimony that E3 failed to properly model the ORDC by making that curve static, thereby understating future revenues in the energy-only market and altering the build and retention signals impacting the loss of load expectation in the report. The IMM asserts that the current ORDC is delivering significant additional revenues to current generators that is not reflected in the E3 analysis.

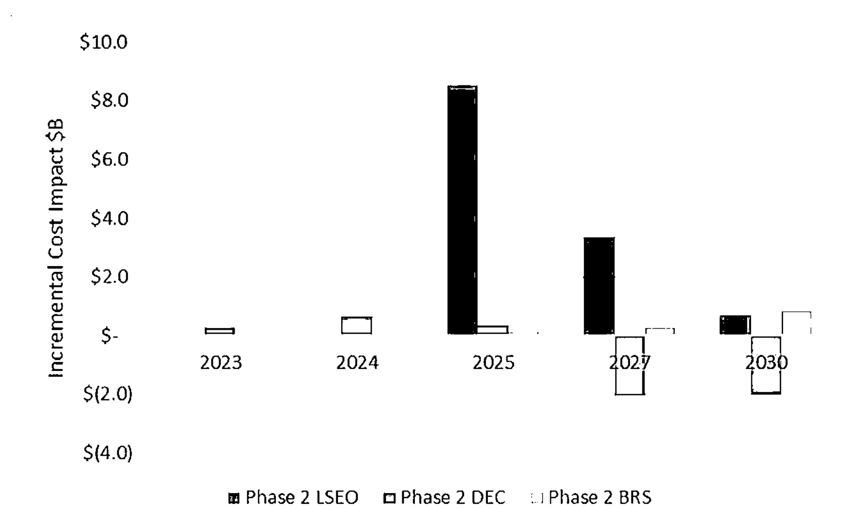
5) By studying and reporting results for a single year (2026), the E3 report gives a misleading snapshot rather than a comprehensive examination of mid- and long-term market impacts.

The E3 report evaluates and reports the Phase 2 reliability options only for the year 2026. This is inappropriate because these policies, intended to affect ERCOT electric wholesale market costs and resource investment decisions over decades, will have substantial resource and cost impacts before and long after 2026. Evaluating policy impacts for a single, near-term year does not provide a useful, comprehensive view of reliability and cost impacts for ERCOT and Texas reliability prospects over the longer term. A useful analysis of reliability options would look at their reliability and cost impacts over a longer time period.

E3 estimates that full implementation of most of the evaluated proposals could take 2 to 4 years [E3 Table 39, pp. 81-82]. However, implementation would not start until the final proposal is verified after the close of the 2023 Legislative session, interpreted and adopted by rule, and incorporated into ERCOT protocols in early 2024 at best – which means market operation and price impacts might not take effect until 2025 or 2026, and meaningful investment impacts attributable primarily to the new reliability measure might not begin until 2026 and later years. Thus 2026 reflects transitional rather than stable long-term program outcomes evident in later years.

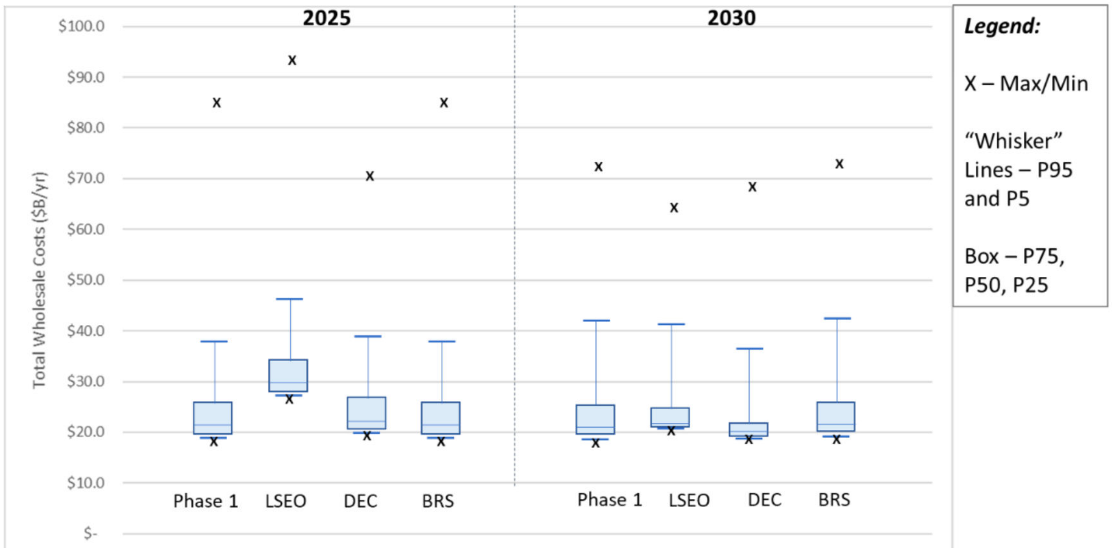
Consider two illustrations from the recent Texas Consumer Association report by ICF analyzing ERCOT market reform options. Although that report studied slightly different reliability mechanisms than the modified mechanisms studied by E3, it illustrates how the impacts of alternate mechanisms change over the early implementation years of 2023 through 2025 and the early results period of 2026 through 2030.

Figure 4 – Incremental cost impact over Phase 1 is highest for LSEO and negative for DEC

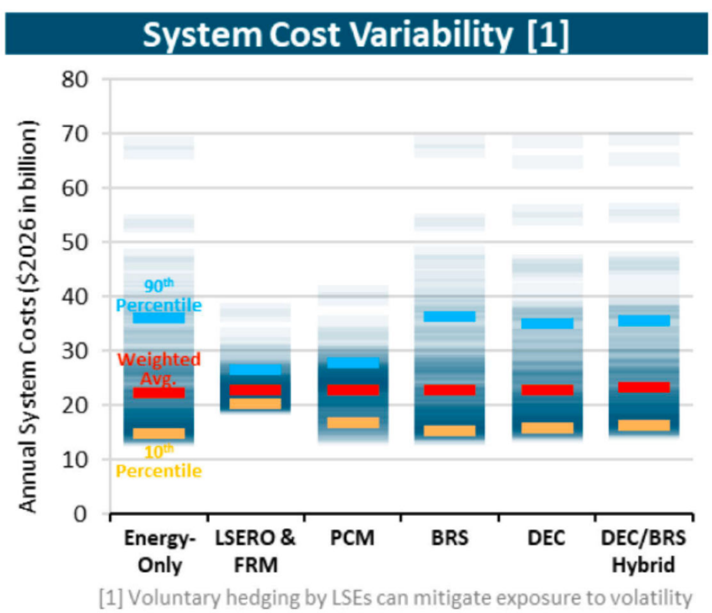


Furthermore, the range and volatility of cost and reliability impacts can vary significantly over time, as illustrated in the ICF figure below. This shows the wide range of potential cost outcomes estimated by the underlying Monte Carlo analysis of many weather, load, outage and other conditions in each year studied – but the E3 study, which reports only average results for a single year, masks the breadth of this potential risk and variability.

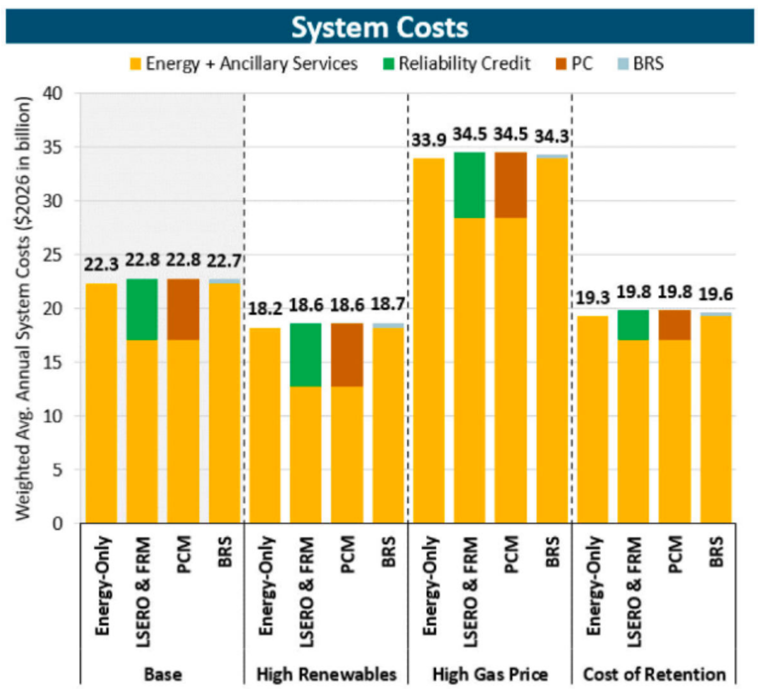
Figure 31: Cost variability decreases by 2030 under LSEO and DEC



The impacts of system cost variability could become very burdensome over a longer time period beyond 2026. Note the breadth of cost exposure that E3 reports for the alternate reliability mechanisms in Figure 2, where 2026 total wholesale system costs could rise from the average $22 billion in 2026 to as high as $70 billion. (below, E3 p.5). This span of cost variation could expand over time, but examination of 2026 alone obscures that risk.



We should also question E3's finding that under a variety of base assumptions and sensitivity cases, total system costs will be near-identical in all cases and the cost of alternate reliability mechanisms will be a decrement rather than an addition to the total system costs of the energy-only market base case. This is shown in E3's Figure 3 (below, from E3 p.7). Recall that E3's base case has been artificially constructed to be very costly with very low reliability, to make the reliability mechanisms look better in comparison; but if these reliability mechanisms do not yield new generation by 2026, as E3 models, then all costs could be higher while reliability is lower in 2026 and subsequent years.



6) E3 undercounts resources and distorts resource need with unique "peak net load" definition.

E3 identifies the "periods of highest reliability risk, measured as the hours of lowest incremental available operating reserves," [E3 p.15] stating that "these are typically, but not exclusively aligned with peak net load." E3 defines peak net load as "the maximum total electricity demand in a system during a specified time period … net of wind, solar and storage generation." [E3 p. viii] This definition and framing of peak net load is unusual and inappropriate. Net load is conventionally defined as total electric demand less wind and solar generation (see, e.g., this discussion of ERCOT regulation service) and represents the demand that must be met with flexible, dispatchable sources such as natural gas, hydropower, demand response, aggregated distributed energy resources, imported electricity, and other resources. [See, e.g., EIA] Energy storage is a dispatchable resource with discretionary charge and discharge cycles, and should be treated as a dispatchable resource rather than as an uncontrollable decrement to load.

E3's choice to treat storage – one of ERCOT's fastest-growing dispatchable resources – as uncontrollable and non-dispatchable systematically lowers the quantity of "load" that dispatchable resources must serve, under-counts available dispatchable resources and lowers the amount of potential resources needed to assure adequate supply reserves. This makes it easier for E3 to assert that the reliability measures studied improve reliability at a low incremental cost.

7) **The E3 study treats energy efficiency and demand response as discretionary decrements to load rather than as resources that could be intentionally designed and used to improve ERCOT system reliability and lower customer costs.**

This is a critical oversight, as load resources actively participate in today's ERCOT market to provide reliability services and there are more resources available than ERCOT now procures. Demand response and aggregated distributed energy resources should be treated as essential grid management resources for better reliability and lower cost. Energy efficiency should be used aggressively as a low-cost, dependable and predictable way to improve reliability by reducing and stabilizing loads. If Texas leadership is willing to pay $93.5/kW-year or more as the cost of new entry for dispatchable generation, that same value should be the capacity cost-effectiveness threshold for new energy efficiency and demand response measures.

Specific PUCT Questions

1) Lack of precedent for implementing PCM – Yes, the lack of precedent for adopting PCM is a significant obstacle to its successful implementation in ERCOT. Other regions have been working on capacity market mechanisms for almost two decades and are still making design and calibration revisions every year because the capacity outcomes and costs have not consistently yielded the expected or desired results. PCM is a novel, complicated, ill-explained and under-documented mechanism. It requires much more development and study before we risk its use in ERCOT. In particular, absent more detailed backcasting and forward analysis of the causes of PC-qualifying hours with the lowest operating reserve margin, we will not know whether the PC mechanism might fix or miss on either ERCOT's resource and energy adequacy problem or the operational flexibility problem.

2) Would PCM incentivize generation performance, retention and market entry? Since the current ERCOT market regime is already incentivizing retention and development of significant new gas-fired, battery and renewable resources, there is no guarantee that PCM will bring about <u>better</u> generation performance, retention and market entry. Because the Performance Credit payout hours can't be identified until the close of the evaluation season and will likely be caused by a variety of semi-predictable issues (high thermal outages, poor load forecasts, low renewable output), it will be difficult for generators to assure their availability and operation during those unspecified hours and predict their future PC revenues accurately. Further, the resource owners will not receive their performance payments until after the entire performance period. This would make all generators' PC revenues deferred and unpredictable, making new plant financing and market entry less financeable. The PCM could incentivize existing generators to avoid building new plants in order to maintain scarcity and high energy prices, while raking in PC payouts for their existing plants.

3) What is the appropriate reliability standard for meeting demand during net peak and extreme load conditions? No single reliability standard can solve both of those problems. As these comments explain above, the Loss of Load Expectation standard is misleading with respect to ERCOT's reliability situation because it is capacity- rather than energy-based and may not reflect common failure modes such as cold weather equipment failures, high temperature deratings or unreliable fuel delivery. LOLE also ignores critical reliability dimensions such as the magnitude of Expected Unserved Energy and the duration of outage events – a summer ramping shortfall can have very different outage, human and economic consequences than an arctic winter generation or fuel supply failure. In 2021, ERCOT's 43% winter reserve margin did not protect us from the disastrous operational failures of Winter Storm Uri.

If Texas does adopt electric reliability standards, those should be targets rather than absolute mandates. The problem with absolute standards is that they demand performance without regard to cost, and too often encourage uni-dimensional rather than multi-dimensional solutions. Real, growing threats from extreme weather, supply chains, and cyber and physical terrorism cannot be factored into reliability standards but will affect ERCOT partners' ability to keep the bulk power system functioning effectively. At a time when Texans face high retail electric prices and inflation across most household and business expenses, we must look for ways to maximize reliability cost-effectively within the limits of bearable costs, not adopt and pursue reliability absolutes without regard to cost.

4) & 5) The E3 study examines 30 hours of reliability risk over a year. Is this the appropriate number or hours or appropriate measure and over what time period? No.

We cannot identify the appropriate reliability risk measure (such as number of hours per year, season or month) without performing more detailed back-casting and near-term analysis to identify the timing patterns and causes for the highest-risk hours for capacity and energy adequacy and fast operational flexibility.

Although E3 asserts that most of the resource shortfalls are likely to occur during peak net load conditions, we are seeing increasing stress to the grid during shoulder periods when high numbers of generation and transmission lines are out for maintenance, with many causes for low operating reserves. ERCOT should test the E3 resource shortfall timing assumptions by back-casting across the years 2019 through 2022 to identify the top 30 and 100 hours in each year (and by season, and by month) when system reserve shortfalls were highest in percentage terms based on the E3 definition of peak net loads (including storage as part of net load rather than as a resource), and under conventional net load reserve shortfalls under actual operating conditions that reflect both weather conditions and generator maintenance and forced outages. This back-cast should identify what caused the shortfall (high load? high thermal outages? low renewable output?) in each period. This comparison could reveal whether operating reserve shortfalls and high reliability risk hours are random or predictable and therefore manageable for generator planning and LSE hedging and procurement. It would also inform whether ERCOT has a resource and energy adequacy problem or an operating flexibility problem and whether the PCM is capable of helping to solve either problem.

ERCOT's reliability risk measures should be informed by what reliability problem we are trying to solve and whether high-risk hours are concentrated in a few days and hours, and whether they are caused by extreme weather or high thermal outages, poor load forecasts, or sudden, unanticipated renewable output drops or load spikes.

7) **Does a centrally cleared market through ERCOT sufficiently mitigate the risk of market power abuse? Should additional tools be considered?** No, a centrally cleared market for PCs will not mitigate the risk of generator market power abuse. While this pre-compliance market design and timing is still unclear, it appears that the centrally cleared PC market would occur after all of the PC hours have been identified. This market would not keep generators from withholding energy offers over the operating period to increase scarcity, nor from preferential contracting with retail affiliates for forward PCs covering potential high-risk hours ahead.

8) **Is there a need for a short-term bridge product or service like BRS to maintain system reliability?** Yes. If the Commission's goal is to maintain the ability to meet very high loads under extreme weather or outage circumstances until load is better managed and there are more dispatchable resources to serve it, then we must defer and manage retirements of existing plants for several years until there is policy stability, implementation certainty and impact clarity and new resources are clearly on the way. A BRS plus firm fuel policy aimed at pulling some older thermal plants gradually out of energy market competition and retaining them purely for emergency operation for a limited time would enhance cost and resource certainty as we work to develop and implement longer-lasting reliability measures.

There are already significant amounts of dispatchable generation and storage in the ERCOT interconnection queue. It is unlikely that the PCM would produce additional new dispatchable resources quickly given the likely delays associated with legislative approval of any reliability mechanism, determination of its many details through Commission rulemaking, ERCOT implementation through protocols and software, and resource financing, queue clearance and equipment acquisition and construction. Therefore, adoption of a bridge reliability measure such as BRS would provide belt and suspenders for reliability and market stability.

9) Is there an alternative to a bridge solution that could be adopted immediately? Yes. In conjunction with adopting the BRS with firm fuel requirements, the Commission should work aggressively to hasten and expand the use of energy efficiency and demand response to slow the growth of peak and extreme weather-driven peak demand and grow demand flexibility as a tool to address operational ramping needs. These are an essential bridge mechanism that will deliver long-term benefits in terms of electric reliability, resilience and affordability. The Commission can also ask the Legislature to adopt more aggressive energy efficiency building codes and standards, direct state and local government facilities to invest in energy efficiency and demand flexibility measures and drop load early in the event of a resource shortfall, and require crypto miners to drop 50% of their load without monetary compensation before ERCOT moves into emergency operations mode and asks citizens for voluntary electricity conservation.

10) **What is the impact of the PCM on consumer costs?** This is impossible to answer because the PCM proposal is still being articulated and modified and the E3 analysis does not credibly assess its costs and reliability. E3 claims that for 2026, $5 billion of Performance Credits will net out against total energy market costs; but this appears highly unlikely. If the PCM does not deliver new dispatchable resources at the optimistic rate assumed, or if it is highly susceptible to market gaming and abuse, if ERCOT badly misses load forecasts and poorly manages generator availability, or if PCM is implemented in a way that rewards thermal generators but burdens renewables, then customers will bear the consequences in add-on PC costs and higher total wholesale costs.

The delayed, end-of-period identification of PC hours will make it hard for Load Serving Entities to predict which hours will be reliability-short, how to manage reliability risks, and what level of hedging and PC costs to build into customer charges. This higher level of uncertainty and risk will in itself increase costs to retail consumers even if it doesn't raise wholesale market costs.

As E3 acknowledges, excluding renewable resources from receiving reliability payments would make the mechanism less effective: "If 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 mechanism", reduce their revenue streams relative to fossil plants and cause fewer renewables to be built. [E3 p.84]. Wind and solar generation are low-cost resources that lower total ERCOT costs and buffer ERCOT customers from high and occasionally volatile natural gas prices; therefore, denying PC payments to wind and solar units would cause less wind and solar to be built, increase gas-fired plant builds, and raise total energy costs. [E3 p.84].

11) **What is the fastest and most efficient manner to build a bridge product or service such as the BRS?** Go back to Commissioner Cobos' original BRS proposal, aimed at deferring the retirement of some existing older thermal plants, and the ERCOT responses about how to implement it. Make an initial determination of how many MW and units would make a meaningful contribution to filling in the potential resource shortfall under severe extreme weather high demand, low supply conditions over a five-year period, using forward-looking extreme weather conditions that include the events of 2021 and 2022. Open an RFP that specifies BRS performance requirements and penalties and invite bids from generators to determine the availability and cost of 3-year forward BRS contracts with limits on how long any unit can retain BRS status before fully retiring. Select the lowest-cost of these resource bids up to the time and resource need limits. Lay out a clear public plan that indicates when the specific units will be pulled out of the energy market into BRS service, to show the timing and path of

new resource need and scarcity revenue opportunities. At the same time, direct ERCOT to minimize out-of-market Reliability Unit Commitments as quickly as possible.

How should the PUCT move forward on Phase 2 in January 2023?

ERCOT and Texas cannot build and cannot afford a grid that can ride through all threats without any outages. But several measures, taken together, can make our grid more reliable, resilient and affordable. The PUCT should adopt the following measures in January 2023 pending legislative direction:

- Give the Phase 1 measures time to work. Generator winterization, firm fuel service, the ORDC changes and increase in ERCOT Contingency Reserve Service and non-spinning reserves should have materially reduced the likelihood of another Winter Storm Uri generation failure, even without proven winterization of the gas production and delivery system. The Phase 1 changes are delivering rich revenues, already exceeding the CONE, and new dispatchable resources are already responding.
- Do adopt Backstop Reliability Service tailored to defer and manage retirements of older thermal plants over the next 5-8 years, and reduce non-spinning reserve and reliability unit commitment amounts and costs.
- Use back-cast and forward analysis to better understand the timing, nature and causes of capacity and energy adequacy and operational flexibility problems in ERCOT. Use these insights to identify relevant reliability metrics and standards and test alternate ancillary service products and resource incentive mechanisms.
- Conduct fresh, credible analyses of the available reliability mechanisms to understand their suitability, reliability impacts, costs and cost-effectiveness. Examine PCM, DEC, the Independent Market Monitor's Uncertainty ancillary service product, and aggressive energy efficiency and demand response, both individually and in combination with other measures, before adopting a formal reliability standard or any additional market reforms.
- Do not adopt the PCM at this time. It is ill-defined, poorly studied, potentially costly, and may not solve ERCOT's actual reliability needs.
- Adopt additional near-term operational reliability measures:
    - Require all crypto mining to cut load by 50%, uncompensated, as the first step before declaring an operational energy emergency. Retain compensation and timing provisions for the other half of crypto load.
    - Require all ERCOT Load-Serving Entities to be able to deliver 2% of peak summer and winter demand as dispatchable, verifiable load reductions within 2 years. By 2027, require all LSEs to have no less than 5% of their total summer and winter peak demand as dispatchable demand response or load management on a 30-minute or faster trigger for 2-hour sustainable load reduction and another 5% of peak as 1-hour trigger, 4-hour statistically sustainable load reduction. These should include the use of Aggregated Distributed Energy Resources.

- Accelerate work on energy efficiency and demand response rule revision to gain substantial increases in the amount of lasting summer and winter peak reduction and demand flexibility. Set much higher efficiency and peak reduction goals, higher funding levels, lower customer co-payments, greater engagement of REPs and LSEs in service delivery and activation, and higher energy and capacity cost values for determining portfolio cost-effectiveness. If Texas leadership is willing to pay $93.5/kW-year or more as the cost of new entry for generation, we should be using that same value as the capacity cost-effectiveness threshold for new energy efficiency and demand response measures. Access all available federal funds and programs to finance these energy efficiency and demand response improvements.
- Begin clear public reporting of monthly and year-by-year totals of the wholesale costs that ERCOT is incurring to improve reliability (ORDC, non-spinning reserves, reliability unit commitment, congestion costs, ECRS and others), and also for the fees and costs that have been added onto retail bills to cover the costs of Winter Storm Uri.

PROJECT NO. 54335

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

PROBLEMS WITH THE E3 "ASSESSMENT OF MARKET REFORM OPTIONS TO ENHANCE RELIABILITY OF THE ERCOT SYSTEM" REPORT FOR THE PUBLIC UTILITY COMMISSION OF TEXAS, NOVEMBER 2022, AND COMMENTS ON THE PUCT QUESTIONS OF NOVEMBER 10, 2022

The E3 report contains significant analytical and methodological flaws that bias its findings on reliability policy options, and it would be a grave error for the Commission to base ERCOT market reform on the conclusions in this report. Many of those flaws misrepresent ERCOT's reliability risk while overstating the reliability benefits and understating the costs of the market reform options studied.

1) The E3 report is focused on solving the wrong problem using an inappropriate LOLE metric. Although E3 finds that ERCOT has LOLE = 0.03 with current resources and loads, the ERCOT grid has operated on the edge of outages repeatedly this year due to combinations of high demand, low wind and high thermal outages. ERCOT remains at risk of deep supply shortfalls this winter. LOLE does not capture operational flexibility problems and insufficiently captures the many dimensions of capacity and energy resource adequacy problems.
2) The E3 study doesn't adequately address the reliability challenges associated with more extreme weather and extreme load. It examines historic extreme weather events but excludes the 2021 Uri winter event, 2022 heat waves and forward-looking extreme weather conditions that may have higher ferocity and frequency than the historic dataset.
3) The E3 study underestimates thermal generator outages and assumes perfect fuel supply despite Uri failures.
4) By arbitrarily removing 11.5 GW (nearly 20% of the ERCOT thermal fleet) in three years, the E3 analysis fabricates a scenario of extreme scarcity, poor reliability and high costs in the energy-only baseline case, then "fixes" it by adding in new generation attributed to the reliability mechanisms.
5) E3 modeled the ERCOT ORDC curve incorrectly, understating future energy-only market revenues and lowering the size of the baseline case incentives.
6) By studying and reporting results for a single year (2026), the E3 report gives a misleading snapshot rather than a comprehensive examination of long-term market impacts.
7) E3 undercounts resources and distorts resource need with unique "peak net load" definition that ignores the dispatchable value of storage resources.
8) The E3 study treats energy efficiency and demand response as discretionary decrements to load rather than as resources that could be intentionally designed and used to improve ERCOT system reliability and lower customer costs.

How should the PUCT move forward on Phase 2 in January 2023?

ERCOT and Texas cannot build and cannot afford a grid that can ride through all threats without any outages. But several measures, taken together, can make our grid more reliable, resilient and affordable. The PUCT should adopt the following measures in January pending legislative direction:

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  - Require all Load-Serving Entities to be able to deliver 2% of peak summer and winter demand as dispatchable, verifiable load reductions within 2 years. By 2027, require all LSEs to have no less than 5% of summer and winter peak demand as 30-minute or faster trigger, 2-hour sustainable load reduction and 5% as 1-hour trigger, 4-hour statistically sustainable load reduction. These should include the use of Aggregated Distributed Energy Resources.
- Accelerate revision of the energy efficiency and demand response rule to gain substantial increases in the amount of lasting summer and winter peak reduction and demand flexibility.