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

TEXAS INDUSTRIAL ENERGY CONSUMER'S COMMENTS ON THE MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC.

I. INTRODUCTION

Texas Industrial Energy Consumers (TIEC) is an unincorporated trade association made up of large industrial companies that have significant electricity needs in the state of Texas. The long-term reliability of the ERCOT system is critical for TIEC members, as they are engaged in energy-intensive businesses that depend on a continuous and reliable supply of electricity. Not only do outages result in plant shutdowns and loss of productivity, but many TIEC member facilities are extremely sensitive to system disruptions and can suffer significant and expensive damages[1] from voltage fluctuations and grid instability. Because of this, industrial customers have taken a leading role in ensuring grid reliability during operational events like Winter Storm Uri, including by voluntarily curtailing their demand[2] and reconfiguring their sites to allow any behind-the-meter generation they may own to export power to the grid.[3] These efforts require significant sacrifice from these businesses, as it can often take facilities weeks to return to full capacity after

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[1] This includes direct damages to sensitive facilities, as well as possible environmental discharges if industrial processes are unexpectedly interrupted.

[2] For example, witnesses in Oncor Electric Delivery Company, LLC's (Oncor's) recent rate case testified that during Winter Storm Uri, Oncor's transmission voltage industrial customers voluntarily curtailed their demand or participated in demand response activities that significantly reduced the amount of distribution voltage load like homes and emergency facilities that Oncor was required to shed to maintain reliability. In fact, transmission voltage customers reduced their consumption by more than 40% ***before*** ERCOT issued any load-shed mandate, and by more than 60% during the load shed event. The aggressive demand response by transmission-level customers reduced the amount of load that ultimately had to be shed across the system, benefiting all other customers. *See Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, Docket No. 53601, Rebuttal Testimony of Collin M. Martin, Witness for Oncor Electric Delivery Company LLC at 6-7 (Sept. 16, 2022) (available at: https://interchange.puc.texas.gov/search/documents/?controlNumber=53601&itemNumber=597).

[3] Texas Senate Committee on Business and Commerce Hearing at 13:27:12 (Feb. 25, 2021) (available at: https://tlcsenate.granicus.com/MediaPlayer.php?view_id=49&clip_id=15392).

shutting down. The opportunity cost of those shutdowns is ultimately borne by those companies.[4] After Winter Storm Uri, industrial customers were often the last customers to be allowed back online, in some cases many days after service was reinstated to residential and commercial customers. Accordingly, TIEC members are well acquainted with the very real economic costs of reliability events.

While system reliability is clearly TIEC's number one priority, TIEC believes that the Commission should pursue that objective with an eye toward minimizing costs to consumers. Absent such a focus, market reform can result in massive wealth transfers from customers to generators, with little real benefit to show for it. Because TIEC is concerned with maximizing reliability in an economically responsible way, it has concerns about many of the proposals discussed in the market reform assessment produced by Energy and Environmental Economics, Inc. (the "E3 Report"). As discussed below, TIEC believes that the E3 Report overstates the need for the massive market overhauls it recommends by incorrectly modeling the prospective performance of ERCOT's existing market design. TIEC also believes that the E3 Report understates the costs that those market reforms will impose on customers, while overstating their potential benefits and glossing over exactly how difficult they will be to implement.

The following is an overview of TIEC's thinking with respect to the flaws in the E3 Report, the potential issues with the Performance Credit Mechanism (PCM) proposal, which the Commission's questions focus on, and a market-based solution that could resolve the Commission's reliability concerns in a more efficient and less disruptive way. TIEC does not support the PCM proposal and looks forward to working with policymakers to develop more effective and less costly reforms to the ERCOT market.

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[4] Texas Senate Committee on Business and Commerce Hearing at 13:27:55 (Feb. 25, 2021) (available at: https://tlcsenate.granicus.com/MediaPlayer.php?view_id=49&clip_id=15392).

A. The capacity market constructs discussed in the E3 Report are aimed at resolving an installed capacity shortage that does not exist, and they will not directly address the actual operational uncertainty issues facing ERCOT.

It is important to preface the discussion of the E3 Report by noting that TIEC believes the Commission is attempting to solve the wrong problem. In particular, the E3 Report and all of its suggested market redesign constructs are aimed at resolving an ***installed capacity*** shortage, when in reality the problems facing ERCOT arise from ***operational uncertainty*** surrounding the availability of renewable resources and forced outages of thermal generation across times of high peak load.[5] Notably, the E3 Report itself acknowledged that ***ERCOT does not have a current capacity shortfall***.[6] E3's base case analysis shows the current energy-only market structure achieving the antiquated one day in ten years reliability standard both today[7] and in 2026.[8] Further, recent experience has shown that power supply gets tight in ERCOT during intervals when there is a combination of low renewable production and forced outages of thermal generation, and ***not*** because demand outstrips installed capacity.[9] At the House State Affairs Committee hearing on December 5, 2022, Chairman Lake noted that over the last 18 months, ERCOT would have gone into emergency conditions at least 8 times but for the Commission mandating that ERCOT adopt

[5] As discussed below, "net peak load" is the differential between the amount of demand on the ERCOT system and the production of intermittent renewable resources like solar and wind. High net peak load occurs when consumption is high and wind and solar production is low, which occurs primarily in the summer months. This is in contrast to "low reserve hours", which can occur in low-load periods where insufficient units were committed. In these periods there is no "installed capacity" problem.

[6] As discussed below, the capacity shortages that E3 projects for 2026 and beyond are the result of questionable modeling assumptions that do not stand up under scrutiny.

[7] E3 Assessment of Market Reform Options to Enhance the Reliability of the ERCOT System ("E3 Report") at 7 ("today's system appears to be close to the 0.1 day/yr benchmark…").

[8] E3 Report at 46 ("Without further adjustments to the resource mix beyond CDR additions and retirements, the "pre-equilibrium" 2026 portfolio would achieve an LOLE of 0.02 days per year, more reliable than the common industry benchmark of 0.1 days per year.") (emphasis added).

[9] If ERCOT had a pure installed capacity shortage, then tight conditions would necessarily coincide with the periods of highest demand. However, that has not been the case in recent years. For instance, ERCOT had a comfortable amount of reserves when it set its all-time peak demand this summer because renewable production was high at that time.

a more conservative operating posture.[10] Critically, however, the system did ***not*** go into emergency conditions precisely ***because there was adequate installed capacity to meet demand across these periods***. While it is true that some of that capacity is currently being kept online though out-of-market mechanisms like reliability unit commitment (RUC), the current problem is not that ERCOT needs more dispatchable generation, but rather it needs a market-based solution to incentivize more fulsome unit commitment across periods of high net peak load. This is not to say that ERCOT will not need additional dispatchable resources in the future, or that reforms are not necessary to ensure long-term resource adequacy. However, as noted below, TIEC believes there are better, more targeted approaches than those outlined in the E3 Report.

Most of the solutions suggested in the E3 Report are poorly suited to solve ERCOT's operational uncertainty issues. Other than the Backstop Reliability Service (BRS) and the Dispatchable Energy Credits (DEC) proposal, the market redesign constructs discussed in the E3 Report would all create some form of capacity market. The Forward Reliability Market (FRM) is a Northeast-style capacity market. The Load Serving Entity Reliability Obligation (LSERO) is a decentralized capacity market like is used in California. And the PCM is a novel capacity market construct that allocates costs to customers on a backward-looking basis. Crucially, none of these capacity market plans would directly target ERCOT's operational uncertainty issues, and none of them would comply with the Legislature's directive from SB 3. In particular, the Legislature instructed the Commission to ensure that ERCOT establish a reliability standard and procure "***ancillary or reliability services***" to ensure appropriate reliability.[11] In contrast, the FRM, LSERO, and PCM would all require customers to make fixed, government-determined payments (through their LSEs) to achieve a government-determined level of revenue sufficiency for

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[10] Texas House of Representative Committee on State Affairs at 6:53 (Dec. 5, 2022) (available at: https://tlchouse.granicus.com/MediaPlayer.php?view_id=46&clip_id=23711) ("Over the last 18 months we would've been in emergency conditions or black out...").

[11] PURA § 39.159(b) ("The commission shall ensure the independent organization certified under Section 39.151 for the ERCOT power region (1) establishes requirements to meet the reliability needs of the power region; (2) periodically, but at least annually, determines the quantity and characteristics ***of ancillary or reliability services*** necessary to ensure appropriate reliability . . . (3) procures ***ancillary or reliability services*** on a competitive basis to ensure appropriate reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production in the power region. . ..") (emphases added).

generators. This mandated wealth transfer from customers to generators is functionally an electricity tax, and the resulting payments would flow through to generators to reward them for simply owning generation resources, which is the hallmark of a capacity market. However, simply owning installed capacity cannot be fairly characterized as an "ancillary or reliability service," and as such, none of the capacity market constructs discussed in the E3 Report are within the scope of what the Legislature intended when it passed SB 3. Additionally, all of these proposed capacity market constructs would shift the risk of capital investment in generation assets back onto customers, which is something that the Legislature sought to avoid when it deregulated the ERCOT market. Moreover, the Legislature considered and rejected a capacity market yet again only last session.[12]

B. The E3 Report's modeling assumptions are flawed, and it should not be used to justify an extremely complicated and expensive market redesign.

The E3 Report has clear and major flaws, and it does not support embarking on a massive market redesign that will be difficult to implement and will permanently increase customers' power costs by hundreds of millions of dollars per year. The Independent Market Monitor (IMM) and other witnesses have detailed the flaws in E3's models at various hearings in front of the Legislature and the Commission, but their analysis bears repeating. The most glaring issues with E3's analysis are as follows.

i. E3's model overstates anticipated thermal generation retirements under the current energy-only market construct and effectively manufactures a projected capacity shortage.

1. The E3 Report overstates the amount of revenues that will be necessary to keep existing generation units from retiring.

The most critical flaw in the E3 Report is E3's unsupported conclusion that approximately 11,260 MW of thermal generation will retire between now and 2026 if ERCOT continues with the

[12] House Bill (HB) 4378 would have required the Commission to adopt seasonal or annual procurement of generation capacity, but the Legislature left it pending in committee. (available at: https://legiscan.com/TX/bill/HB4378/2021). Instead, the Legislature approved SB 3, which required the Commission procure ***ancillary or reliability services*** on a competitive basis. PURA § 39.159(b)(3).

current energy-only market.[13] This assumption is what creates the high loss of load expectation (LOLE) for the energy-only market in E3's projections for 2026. As the IMM explained to the Senate Business and Commerce Committee on November 17, 2022, to arrive at that amount of projected retirements, "[E3] assumed in any individual year that if [an existing generator's market-derived] revenues above [its] fixed costs recovery did not equal cost of new entry [("CONE") for a greenfield combustion turbine], then the generator would retire."[14] This is a nonsensical approach, because the capital cost of an existing unit is sunk and irrelevant to its retirement decision. Moreover, the ongoing cost to operate an existing unit is unrelated to the cost to build a new combustion turbine at an undeveloped site. To that point, according to the IMM, E3's retirement assumption "is an overstatement of the market equilibrium mechanisms," which is apparent because "[w]e have hit CONE twice in the last ten years . . . but we do not see 11,000 MW of retirement."[15] In fact, as shown on Table 60 of the E3 Report, ERCOT has actually ***gained*** nearly 4,200 MW of dispatchable natural gas generation since 2020, and the rate of new natural gas build in recent years has far outstripped coal retirements, which have been minimal since Luminant closed three large coal facilities in early 2018.[16]

As the IMM and other witnesses have explained, E3 should not have assumed that dispatchable generation will retire if the market does not provide net revenues that exceed the CONE of a peaking gas turbine, because resources decide to retire or not based on whether they expect to recover their ongoing ***incremental*** operating costs, not the cost of entering the market.[17]

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[13] E3 Report at 5.

[14] Texas Senate Committee on Business and Commerce Hearing at 2:25:21 (Nov. 17, 2022) (available at: https://tlcsenate.granicus.com/MediaPlayer.php?view_id=52&clip_id=17072); *see also* E3 Report at 3 ("Equilibrium is achieved by adjusting the quantity of coal and natural gas resources under each design such that the net margins earned by the marginal capacity resource across all potential market products (energy, ancillary services, or other new market products if applicable) are equal to its cost of new entry (CONE).").

[15] Texas Senate Committee on Business and Commerce Hearing at 2:25:21 (Nov. 17, 2022) (available at: https://tlcsenate.granicus.com/MediaPlayer.php?view_id=52&clip_id=17072)

[16] E3 Report at 133.

[17] Texas Senate Committee on Business and Commerce Hearing at 2:25:50 (Nov. 17, 2022) (available at: https://tlcsenate.granicus.com/MediaPlayer.php?view_id=52&clip_id=17072) ("Resources will make a decision every year about whether to stay in the market or exit the market ***based on their ongoing cost of retention***, its different for each resource and about their expectations in market revenue going forward.") (emphasis added).

Since CONE includes the initial capital cost of a new facility, incremental operating costs are generally far below CONE. Accordingly, by assuming that a huge amount of thermal generation will retire if peaker net margin (PNM) is below CONE, the E3 Report unduly inflated anticipated retirements and thereby manufactured the projected capacity shortage that it uses to justify its recommendation to radically modify the ERCOT market.

The E3 Report acknowledges that the market does not need to provide existing generation units with revenues that exceed CONE in order to prevent them from retiring. As the report notes, "if the system has a short-run surplus of capacity, resources may not need to recover their full gross CONE in order to stay in the market without retiring. Rather, these resources may only need to recover their go-forward cost of operation, [or] fixed operations and maintenance."[18] Importantly, as noted above, ERCOT ***does*** currently have a surplus of capacity, because in E3's "Base Case," "[w]ithout further adjustments to the resource mix beyond CDR additions and retirements, the "pre-equilibrium" 2026 portfolio would achieve an LOLE of 0.02 days per year."[19] In other words, absent E3's aggressive retirement assumption (discussed above), ERCOT will far exceed E3's reliability target in 2026.

Perhaps in recognition of the aggressiveness of its retirement assumption, E3 included a sensitivity "Low Cost of Retention Equilibrium" that is based on whether the market will provide sufficient revenues to exceed existing generation units' going-forward cost of operation.[20] But even in that case, E3 used flawed assumptions that cause it to significantly overstate the amount of dispatchable generation retirements that would occur at equilibrium. E3's "Low Cost of

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[18] E3 Report at 72.

[19] E3 Report at 46.

[20] *See* E3 Report at 72-74. It is worth noting that in a sensitivity analysis that more reasonably assumes that existing generation will only retire if it cannot cover its fixed O&M costs, the LOLE in equilibrium decreases by nearly two thirds, but the cost of implementing alternative market designs to get the LOLE down to E3's 0.1 target remains essentially the same, meaning that customers will pay the same amount for a much smaller anticipated improvement in reliability. E3 Report at 73 ("Under the Energy-Only design, the Low Cost of Retention sensitivity results in the retention of more natural gas capacity (less equilibrium retirements), ultimately leading to a higher level of reliability than in the Energy-Only Base Case: ***the LOLE in equilibrium decreases from 1.25 to 0.47 days per year***.") (emphasis added); *id.* ("[T]he incremental cost of alternative market designs [in the Low Cost of Retention sensitivity] is similar to the Base Case and other sensitivity results.").

Retention Equilibrium" assumes that existing generators in ERCOT will need revenues of ***$50/kW-yr*** in order to satisfy their ongoing cost of retention and avoid retirement,[21] but that number is far too high and not based on real generator operating costs. E3 explains that it based this equilibrium point off of an EIA estimate of coal plant fixed O&M costs, which range from $40-55/kW-yr.[22] However, a review of the report that E3 cites shows that its low-end $40/kW-yr fixed O&M cost projection is for a new, modern ultra-supercritical coal facility, and that the $55/kW-yr cost is for a similar facility with carbon capture technology.[23] But the fixed O&M costs for an average fossil steam unit in 2021 is much lower,[24] so E3's "Low Cost of Retention Equilibrium" forces more retirements than would actually occur by inflating those units' fixed O&M costs. Additionally, the EIA report that E3 cites shows that the ongoing fixed O&M cost for new natural gas turbines is much lower— in the range of ***$12-16/kW-yr***[25]—so it would be reasonable to expect that existing natural gas generation in ERCOT would not retire if revenues exceeded that level. Nevertheless,

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[21] E3 Report at 72.

[22] E3 Report at 72 and note 42.

[23] *See* U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies* at PDF page 2, Table 2 (Feb. 2020) (available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_aeo2020.pdf) (cited by E3 Report at 72, note 42).

[24] Data shows that it costs approximately **$34.7/kW-year** to maintain an average fossil steam unit in ERCOT.

- EIA average Fossil Steam O&M expense in 2021 was $11.02/MWh. *See Table 8.4 Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 2011 through 2021*, EIA (available at: https://www.eia.gov/electricity/annual/html/epa_08_04.html) (showing that Fossil Steam unit operation costs are $5.70 and maintenance costs are $5.32).
- Fossil steam units in ERCOT produced 80.6 GWh in 2021. *See Form EIA 923 Detailed Data*, EIA (available at: https://www.eia.gov/electricity/data/eia923/).
- There were 25,562 MW of fossil steam units in ERCOT's December 2021 CDR. *Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2022-2031,* ERCOT (Dec. 29, 2021) (available at: https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.xlsx).
- Multiplying the operational costs, $11.02/MWh, by the volume of fossil steam units in ERCOT, 80,600,000 MWh, and dividing it by the total megawatts of fossil steam units, 25,562 MW, shows the average cost per year of a fossil steam unit in ERCOT to be $34.7/kW-yr.

[25] *See* U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies* at PDF page 2, Table 2 (Feb. 2020) (available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_aeo2020.pdf) (cited by E3 Report at 72, note 42).

E3's "Low Cost of Retention Equilibrium" still projected that over 3,100 MW of natural gas generation will retire between now and 2026. This conclusion is unsupported by actual data and is incorrect. So once again, even in E3's "Low Cost of Retention Equilibrium," its flawed assumptions create an artificial capacity shortage that drives the purported need for massive market reforms.

2. The E3 Report incorrectly assumes that generators only derive revenues from real-time sales.

The E3 Report's projected thermal generation retirements are also inflated because E3 assumes that generators' retirement decisions are controlled exclusively by the amount of revenues they can obtain from sales in the real-time market. But in reality, only about 20% of energy transactions are conducted in the real-time market.[26] The remaining 80% of energy transactions occur through bilateral hedging contracts,[27] which often allow generators to earn a significant premium compared to real-time wholesale prices. In fact, the two largest companies in the market have integrated retail and generation positions and regularly achieve annual margins of $1 billion above competitive retailers.[28] Accordingly, this is yet another reason that the E3 Report overstated the resource retirements that can be expected if the Commission were to continue with the existing energy-only market, which once again manipulates the data in the Report in favor of massively expensive and uncertain market overhauls.

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[26] Potomac Economics, *2021 State of the Market Report for the ERCOT Electricity Market* at 9 (May 2022) (available at: https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf) ("Only a small share of the power produced in ERCOT is transacted in the real-time market.").

[27] *E.g.*, Vistra, *Vistra Reports Second Quarter 2022 Results; Authorizes $1.25 Billion for Share Repurchases* (Aug. 5, 2022) (available at: https://investor.vistracorp.com/2022-08-05-Vistra-Reports-Second-Quarter-2022-Results-Authorizes-Additional-1-25-Billion-for-Share-Repurchases) ("Continued executing on comprehensive hedging program, locking in significant value opportunities in future years. As of June 30, 2022, Vistra has hedged over 60% of its expected generation volumes on average for the three -year period 2023 to 2025, with 2023 hedged at approximately 80%.").

[28] This margin is calculated from EIA Form 861 data, which compare the prices and revenues from the TXU Retail and Reliant Energy brands owned by Vistra and NRG to the prices and revenues achieved by competitive REPs. The difference in pricing between these brands and competitive REP brands is the margin premium flowing to the integrated company and its generation. This margin has exceeded $1 billion in each of the last three years.

ii. The E3 Report does not accurately model how changes in ERCOT's resource mix would increase the revenues provided by the ORDC in the energy-only market.

The E3 Report also inflates the LOLE for the energy-only market because it does not model how the parameters of the existing operating reserve demand curve (ORDC) will change as new renewable generation comes online and thereby understates generators' prospective revenues. The ORDC determines the clearing price for energy in ERCOT, and as scarcity increases the price that generators are paid goes up. As the IMM explained to the Senate Business and Commerce Committee, the E3 Report "did not model changes to the parameters of the ORDC over time."[29] "They took this year's [ORDC] curve and just made it static, and put that in 2026 and made that the long run equilibrium curve."[30] That understates the revenues that will be provided by the energy-only market because as the additional solar resources that E3 projects come on to the system, that will increase the amount of intra-hour uncertainty, which will in turn cause the ORDC to produce additional revenues that will send price signals that will incentivize generators to retain their existing resources and invest in new capacity.[31] By ignoring these additional revenues, the E3 Report hobbled the projected performance of the energy-only market, once again inflating anticipated retirements and creating the projected capacity shortage that underlies the recommendation to adopt a capacity market construct.

iii. E3's Report did not model new entry in response to scarcity pricing in the energy-only market.

Yet another flaw in the E3 Report is that it assumes there will be a large amount of dispatchable resource retirements that will create scarcity and increase the revenues produced by the energy-only market, but it does not allow for the possibility that new resources will enter the

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[29] Texas Senate Committee on Business and Commerce Hearing at 2:24:00 (Nov. 17, 2022) (available at: https://tlcsenate.granicus.com/MediaPlayer.php?view_id=52&clip_id=17072)

[30] Texas Senate Committee on Business and Commerce Hearing at 2:24:15 (Nov. 17, 2022) (available at: https://tlcsenate.granicus.com/MediaPlayer.php?view_id=52&clip_id=17072)

[31] Texas Senate Committee on Business and Commerce Hearing at 2:24:53 (Nov. 17, 2022) (available at: https://tlcsenate.granicus.com/MediaPlayer.php?view_id=52&clip_id=17072) ("If we had 20,000 MW of Solar, we believe [the ORDC] parameters would be different, and it would produce more revenue. By producing more revenue, it provides signals for building new resources or retaining existing resources. That's one of the reasons why we think [the E3 Report] overstates retirement.").

ERCOT market in response to those price signals. In E3's base case, the exit of 11,260 MW of dispatchable resources would lead to scarcity and increase prices, resulting in energy-only market revenues of $22.3 billion per year.[32] In E3's extreme weather case, those revenues go as high as $36.1 billion per year.[33] Nevertheless, E3 unrealistically assumes that no new dispatchable generation would enter the market in pursuit of those revenues, which makes the energy-only market appear significantly less reliable than is reasonable to expect. In contrast, when modeling its market redesign proposals, E3 projected that new resources would enter the system in response to increased revenues. The equilibrium price is identical, yet no resources are allowed to enter in the energy-only case, while 5,600 MW are assumed to enter in the capacity market cases. Assuming such divergent results makes no sense. This unequal analysis puts a thumb on the scale in favor of E3's favored market redesign proposals and uniquely and unreasonably disadvantages the energy-only market.

C. Even if the Commission believes that ERCOT will face a capacity shortage if it continues with the energy-only market, it should not adopt the PCM because it is an expensive and potentially ineffective solution.

As an initial matter, it is difficult to comment on the PCM proposal because its characteristics have not been precisely defined and its proponents' descriptions of how it will work have continued to shift since the E3 Report was released. Nevertheless, at a high level, it appears that while the PCM may be slightly better than other capacity market constructs in some respects, it would still create a massive mandatory wealth transfer from customers to generators without any guarantee that new generation capacity will be built. As discussed at recent legislative hearings, ***the PUC has no ability to command capital***, and cannot force competitive generators to build new dispatchable facilities in response to the additional revenues that the PCM would provide. But customers will be required to provide those revenues regardless. The E3 Report's analysis shows that ***the PCM will cost consumers $5.7 billion per year*** compared to the current energy-only market.[34] And while the E3 Report claims that the PCM will only cost customers an incremental

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[32] E3 Report at 5.

[33] E3 Report at 62.

[34] E3 Report at 60.

$460 million per year,[35] that comparison is based on the assumption, critiqued above, that 11,270 MW of thermal generation will retire under the energy-only market, causing massive price increases due to scarcity. As noted previously, this is an unreasonable assumption, and it masks the actual cost differences between the two market designs.

As with applying any capacity market construct to the ERCOT market, the PCM would create a "worst of all worlds" result for consumers—the market would pay a clearing price for energy and a clearing price for PCM credits, with the risk of extremely high scarcity pricing for both, but there would still be ***no guarantee*** that the additional revenues would result in new generation investment in ERCOT. It is easy to envision a scenario where a PCM mechanism leads to significant cost increases for customers without providing sufficient capacity because that exact thing has happened in other capacity markets around the country. For example, increases in renewable resources with lower accredited capacity values caused MISO's 2022/23 capacity auction to fall approximately 1.3 GW short in MISO's northern zones, which led to clearing prices for capacity skyrocketing from $5/MW-day up to $236.66/MW-day.[36] While its exact mechanisms are unclear at this point, the PCM would by definition allow even higher premium pricing[37] for production credits if a situation arises where ERCOT is actually short on capacity and new dispatchable generation does not materialize.

Even if the PCM were adopted, it is not clear that existing generators will build new dispatchable facilities in ERCOT. As an example, despite dramatically increased revenues being paid to generators in the ERCOT market today, incumbent generation companies have recently been spending billions of dollars in cash—not on new dispatchable generation—but on buying

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[35] E3 Report at 60 ("Similar to LSERO and FRM, the $5.7 billion cost to procure PCs in test year 2026 is partially offset by a $5.2 billion decrease in energy and ancillary services costs, resulting in a net system cost increase of approximately $460 million.").

[36] Amanda Durish Cook, *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*, RTO Insider LLC (Apr 14, 2022) (available at: https://www.rtoinsider.com/articles/29948-misos-22-23-capacity-auction-bare-shortfalls-midwest).

[37] MISO's cap was only $86/kw-yr while E3 has suggested that the demand curve for PCM credits be set at 1.5 – 2 times CONE.

back stock,[38] or expanding into new lines of business.[39] There is no guarantee that simply giving these companies more money will cause them to change tack and begin building additional dispatchable capacity. As such, the Commission should consider different and more targeted approaches that do not involve paying billions of dollars to entities that are unlikely to invest in new dispatchable generation in Texas.

D. It will take years to implement the PCM, and new investment will be chilled in the meantime.

The regulatory uncertainty created by adopting a novel and untested market reform like the PCM could itself drive a capacity shortage as generators wait to see what the new market looks like before committing additional capital. The E3 Report notes that "[t]he PCM design is complex and requires significant technical analysis and stakeholder engagement to develop final rules,"[40] and that "[i]t would likely take two years to develop the rules and regulations for the PCM."[41] After that, "the market will need time to respond to the market signals created by [the PCM],"[42] so all told, E3 projects that the PCM will take ***2-4 years*** to fully implement. TIEC questions whether even four years would be long enough for such a massive and controversial market reform. Even uncontroversial reforms with broad support can take many years to go into effect. For example, the Commission asked ERCOT to begin studying the benefits of implementing real-time

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[38] *See* Vistra, Vistra Reports Second Quarter 2022 Results; Authorizes $1.25 Billion for Share Repurchases (Aug. 5, 2022) (available at: https://investor.vistracorp.com/2022-08-05-Vistra-Reports-Second-Quarter-2022-Results-Authorizes-Additional-1-25-Billion-for-Share-Repurchases) ("[T]he board has authorized a cumulative $3.25 billion in share repurchases since Vistra announced its capital allocation plan in Nov. 2021.") (Aug. 5, 2022); *see also* NRG Energy, Inc., *NRG Closes 4.8 GW Asset Sale and Announces $1 Billion Share Repurchase Program* (Dec. 6, 2021) (available at: https://www.nrg.com/about/newsroom/2021/40856.html) ("[T]he NRG Board of Directors has authorized $1 billion for share repurchases, effective immediately. The program is expected to begin in 2021 and will continue throughout 2022.") (Dec. 6, 2021).

[39] *See* NRG Energy, Inc., *NRG, Inc. to Acquire Vivint Smart Home, Inc.* (Dec. 6, 2022) (available at: https://www.nrg.com/about/newsroom/2022/41771.html?utm_source=newsletter-hub-wire&utm_medium=email&utm_campaign=pe-hub-wire-subscriber&utm_content=06-12-2022) ("NRG Energy, Inc. (NYSE: NRG) and Vivint Smart Home, Inc. (NYSE: VVNT) today announced they have entered into a definitive agreement under which NRG will acquire Vivint for $12 per share or $2.8 billion in an all-cash transaction.") (Dec. 6, 2022).

[40] E3 Report at 82.

[41] E3 Report at 82.

[42] E3 Report at 82.

co-optimization in ***2017***,[43] and despite broad stakeholder support and approval for those reforms, they have yet to be completed.

Implementing the PCM will require the Commission to make a number of critically important and potentially controversial judgment calls, each of which will require many months of study and deliberation. First, the Commission will have to decide what types of resources can qualify to receive production credits (PCs), and whether renewables will be allowed to participate. Then, it will need to establish a process to verify whether resources that bid into the system are actually "available" to provide capacity on demand. Otherwise, the market will inevitably end up paying for resources that cannot actually perform when called upon. Refinements will also need to be made to load and generation forecasting, which will have a very large impact on the cost of PCs. After that, the Commission would have to develop an appropriate reliability standard and design a demand curve to price PCs based on that standard, and each of those decisions would have study requirements and ramifications on par with creating a new ORDC—a process that took years. And even after the mechanisms of the PCM demand curve are worked out, the Commission would still need to develop a system for recovering PCM revenues from the market, including establishing a principled basis for assigning the resulting costs to customers. Further, the recovery of PCM costs will have a huge impact on REPs, and the Commission will need to work out systems to allow REPs to hedge PCM costs on a forward basis consistent with the duration of contracts demanded by retail customers, integrate PCM costs into existing contracts, and recover PCM costs from customers who migrate between REPs, all of which will take significant time. And finally, as the E3 Report acknowledges, implementing the PCM would also involve rolling back the Commission's recent changes to the ORDC.[44] The resolution of each of these issues will have

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[43] *Review of Real-Time Co-Optimization in the ERCOT Market*, Project No. 48540, Open Meeting Memorandum at Bates 003 (Aug. 2, 2018) (available at: https://interchange.puc.texas.gov/Documents/48540_2_988594.PDF).

[44] E3 Report at 71 ("Removing the ORDC from the … PCM market design[s] reduces system costs by $417M/year while meeting the 0.1 days/year LOLE reliability standard. These cost savings can be attributed to a reduction in ORDC payments in hours where the economic scarcity created by the ORDC is artificial since there is no physical scarcity in the system. The modeling demonstrated that in many hours – more than 10% of hours for some model iterations – the ORDC is in effect even if there is a significant headroom of uncommitted but available resources in the system, primarily gas CTs. This artificially increases energy and ancillary service costs and is an inefficiency of the ORDC construct.").

massive implications for stakeholders across the ERCOT market, and while the answers remain unclear it is likely that capital will remain on the sidelines, waiting to see how the market will be structured before committing to decades-long investments in new generation facilities. And at the same time, economic development could similarly be chilled due to the uncertainty surrounding this massive market overhaul.

Finally, even once a PCM system is in place, there is a risk that it will not create a stable market that generators and customers can rely on when making capital investment decisions in ERCOT. It has been TIEC's experience in other power pools that regulators often continually tinker with capacity market constructs after they are established, with an eye toward achieving politically motivated objectives such as incentivizing investment in a certain type of resource or clearing the way for a particular facility to be built. These constant shifts in market structure also tend to chill investment in new resources because it is unclear whether the market will perform consistently from year to year.

E. None of the solutions discussed the E3 Report will guarantee new generation development in ERCOT.

One critical caveat to keep in mind with respect to the market reform proposals discussed in the E3 Report is that while they will create a massive forced wealth transfer from customers to generators, those additional revenues ***cannot guarantee that new generation will be built in ERCOT*** because the Commission has no authority to command capital investment. The only way to ensure new dispatchable generation in ERCOT is by procuring it directly. While TIEC believes strongly in competitive markets, in many instances directly procuring new dispatchable generation would be preferable to adopting a capacity construct like the PCM. A direct procurement solution of this type would be similar to proposals presented during the last legislative session, which would involve competitively procuring some pre-determined amount of natural gas-fired generation and providing their owners with a regulated return in order for that capacity to be available for emergencies.[45] Because a direct procurement is cost-based, and is only paid to the entities that

[45] Mark Chediak and Katherine Chiglinsky, *Buffet's Berkshire Floats $8.3 Billion Fix for Texas Grid*, Bloomberg, March 25, 2021 (available at: https://www.bloomberg.com/news/articles/2021-03-25/berkshire-hathaway-floats-8-3-billion-plan-to-fix-texas-grid) (explaining that Berkshire Hathaway Inc. proposed an $8.3 billion plan to directly procure 10 gigawatts of natural gas plants).

provide the resources, it is significantly less expensive than capacity market constructs. And critically, such a program would guarantee actual "steel in the ground."

F. Instead of adopting the PCM or any other capacity market construct, TIEC recommends adopting the Dispatchable Reliability Reserve Service (DRRS) because it will more effectively and efficiently address ERCOT's operational issues.

TIEC is aligned with and supports the filing by the Coalition for Dispatchable Reliability Reserve Service, which recommends resolving concerns about potential capacity shortages in ERCOT by creating a new uncertainty product within the context of the existing energy-only market.[46] An uncertainty product would be within the mandate the Legislature provided the Commission last session in SB 3 because it is a market-based, targeted reliability service that would address the uncertainty created by variations in renewable generation production, peak load, and forced outages of thermal generation. DRRS would be a Day-Ahead Market procured 4-hour service that is available within 2 hours after deployment. Currently, the Commission is shielding against operational uncertainty in ERCOT by procuring significant amounts of out-of-market reliability unit commitments (RUCs). However, these out-of-market actions are expensive for consumers and counterproductive because they distort price signals and prevent the market from incentivizing new investment in generation and demand response. Conversely, creating a targeted ancillary service product that is sized appropriately to address the current and expected variability in ERCOT's net peak load will have a significantly smaller cost impact on consumers than the other market design proposals in E3's Report. Further, it will create price signals for new and existing dispatchable generation. To avoid any unexpected traditional generation retirements while the DRRS price signals attract new investment, the Commission could continue to use existing out-of-market mechanisms like ERCOT's Reliability Must Run (RMR) protocol as a bridge to ensure reliability.

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[46] *Review of Wholesale Market Design*, Project No. 52373, The Coalition for Dispatchable Reliability Reserve Service's Comments (Dec. 14, 2022) (available at: https://interchange.puc.texas.gov/Documents/52373_384_1258736.PDF).

Importantly, DRRS would create the same incentives for new dispatchable generation buildout as the capacity market proposals the E3 Report. However, DRRS would be performance-based and targeted at the type of resource ERCOT needs. As such, TIEC believes it would be less expensive and more effective. Conversely, the PCM would shift a large portion of wholesale market costs toward resources that happen to be available during times of low operating reserves without guaranteeing a commensurate increase in real-time operational reliability. Although there is no guarantee that new resources will be built in either scenario, DRRS at least ensures that consumers are only paying for resources that actually meet the performance attributes ERCOT needs. As such, DRRS would undoubtedly be more efficient and targeted than the PCM.

G. If the Commission decides to move forward with the PCM, the proposal should be modified in multiple ways to make it more effective.

As explained above, TIEC does not support adopting the PCM or any other capacity market construct. However, if the Commission decides to move forward with the PCM, TIEC would recommend the following changes.

i. The Commission should develop an economically rational target reserve margin as a benchmark to guide the PCM.

If the Commission decides to adopt the PCM, its first step should be to develop a rational, evidence-based target reserve margin rather than relying on the antiquated and arbitrary "one-event-in-ten-years" standard used in the E3 Report. The "one-event-in-ten-years" standard only exists as a relic of the days of vertically integrated utility regulation and has changed its meaning considerably as improvements in analytic tools have allowed for more complex planning models. Importantly, a pure "loss-of-load-expectation" (LOLE) standard does not properly reflect the economics of expected outages, the costs of the reserves needed to avoid those outages, or the rational reserve level a market should produce based on these factors. Reliance on this standard has caused repeated "false alarms" about resource adequacy over the years. However, since ERCOT transitioned to competition, ***there have been zero loss of load events driven by resource inadequacy***.

An "event-based" LOLE standard is perhaps the most arbitrary method of setting a target reserve margin. As demonstrated above in relation to the E3 Report's models, the outcome of applying a LOLE standard varies wildly depending on the assumptions that are fed into the LOLE models. Additionally, a LOLE standard does not reflect the duration, magnitude, or cost of expected outages, so it does not place any rational limit on the costs that the market will incur to avoid an outage. An expected unserved energy (EUE) based standard would be preferable, as it reflects the duration and magnitude of the outages and can be adjusted to fit the size of a particular system, but even that metric does not capture the economic impact of outages. It is essential to compare the economic cost of an outage against the costs required to avoid it in order to establish the necessary economic context for a reliability standard. In 2012 the Commission hired The Brattle Group to determine the economically optimal target reserve margin for ERCOT. The Commission should refresh this analysis if it proceeds with the PCM construct.

In a competitive market, where resource additions cannot be mandated and generation plant is not recovered in regulated rates, crafting a reliability standard that is rooted in economics is necessary to foster a stable, well-functioning market. ERCOT's sophisticated scarcity pricing regime and growing demand response options call for an economically optimal reliability standard. The Commission should reject arbitrary event-based metrics that have no market or analytical foundation, and adopt an economically optimal reserve margin as the reliability target instead.

ii. PCs should be assigned based on "net peak load" in the hours when capacity is most needed.

As noted above, it is difficult to provide detailed suggestions for improving the PCM construct because its purported characteristics keep shifting over time. However, one essential feature of any PCM construct is the metric that will be used to determine when PCs are issued. TIEC believes PCs should be awarded to resources for their performance at times of highest "net peak load," meaning the total demand on the system minus intermittent generation production from renewable generation like wind and solar. Traditionally, ERCOT system conditions have been tightest at times when net peak load is highest. For instance, when ERCOT set a new record for system peak demand this past summer, it had a comfortable margin of reserves because renewable production was also high across the peak (meaning lower net peak load, even though load was high). In contrast, the tightest intervals occurred when high demand coincided with low renewable production, and that phenomenon is likely to continue. Accordingly, if the Commission chooses to go with a PCM construct, it should structure it to incentivize resources to be available at the intervals with the highest projected net peak load.

Critically, the PCM should target the intervals with highest net peak load regardless of how those intervals are distributed throughout the year, even if that means that most or all PCs are awarded during the summer months. It makes sense to award PCs to generators for their performance during those most critical intervals. Similarly, costs should be allocated to customers based on their demand at times when reliability risks are highest, which are by definition the highest net peak load hours. Some discussions of the PCM have included the possibility of awarding PCs during the tightest intervals in each month, but such an approach would create irrational incentives for both generation and loads. For instance, if PCs were available during the shoulder months when system conditions are not expected to be particularly tight, that would encourage generators to avoid taking maintenance outages during those months so they could pursue the associated revenues. Similarly, if loads were at risk of incurring PC-related costs during intervals when there is not actually an anticipated capacity shortage, then those negative price signals would incentivize customers to curtail economic activity unnecessarily. In both situations, shifting the costs and benefits of PCs away from the intervals when net peak load is highest would create irrational economic inefficiencies, so the Commission should establish a PCM system that focuses its incentives on the highest net peak load hours in each year.

iii. PCs should be available to any resources that have demonstrated capacity value.

When implementing the PCM, the Commission should not unduly favor any type resource, and should be open to awarding PCs to any resource in proportion to its ability to provide capacity at times of highest net peak demand. This should include load resources, which have already proven to be an invaluable tool for ERCOT to call upon to support system reliability in times of scarcity. Additionally, the Commission should be open to allowing renewable resources to participate in the PCM to reflect their load carrying capability at times of highest net peak demand. The PCM should not ignore the fact that renewables will continue to contribute some capacity value at those times.

II. RESPONSES TO COMMISSION QUESTIONS

1. The E3's report observes that the PCM has no prior precedent for implementation, does this fact present a significant obstacle to its operation for the ERCOT market?

Yes, as explained above, PCM will take years to implement, partially because the

Commission is required to make a number of important and controversial judgment calls, each of which will require months of study and deliberation. E3 projects it will take 2-4 years to fully implement the PCM, but TIEC questions whether even 4 years would be long enough when uncontroversial reforms with broad support, such as real-time co-optimization, have taken even longer than that to go into effect. The lack of prior PCM precedent will also increase regulatory uncertainty, and that uncertainty could itself prompt capacity shortages as merchant generators wait to see what the new market looks like before committing additional capital.

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?

Generation Performance

PCM would likely ***weaken*** the performance incentives for generators that exist under the current energy-only market. Like all other capacity markets, the PCM will reward generators simply for owning generation resources without any requirement that those resources actually perform. Under the PCM construct, resources will be paid if they made a day-ahead offer and were "available" (however that is defined) for certain periods of time, but the mechanism does not appear to include any accreditation process to verify whether resources that bid into the system were actually capable of providing energy. For example, if an expensive, older unit offered into the day-ahead market at the price cap each day, it would rarely receive deployment instructions, but it would be eligible for PCs. Because the PCM does not penalize generators that consistently fail to perform when deployed, resources may have an incentive to make high offers, so they're considered "available," regardless of whether the unit is actually capable of providing additional reserves. Unless the PCM only awards credits to resources that either actually perform or can verify that they could perform, it will likely weaken the market's existing performance incentives.

Generation Retention

Existing generation units may postpone retirement to realize additional revenues from the PCM. However, it is not clear that impending resource retirements are a large enough problem to merit such a drastic market reform. As explained above, the E3 Report significantly overstates the amount of thermal generation that is expected to retire if the Commission continues with an energy-only market construct. While some commenters have pointed to recent generation company bankruptcies as proof that the energy-only market is not retaining existing resources, it is important to emphasize that the only recent bankruptcies of generation companies came in the wake of Winter Storm Uri and were the result of those companies' bad hedging decisions rather than any fundamental flaws in the current market design.[47]

Generation Market Entry

The PCM will certainly result in a substantial wealth transfer from consumers to generators, but ***the PCM cannot guarantee that new generation will be built in ERCOT***. Additionally, the regulatory uncertainty created by implementing a drastic and novel market redesign like the PCM could also deter new capital investment in the near-term, actually hurting resource adequacy.

3. What is the appropriate reliability standard to achieve the goals stated in Question 2? Is l-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)?

See Section G.i above.

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?

E3 did not conduct a study to determine the number of "high risk" hours that would most accurately capture current system topology. Such a study should be done before choosing the number. Note also that many of these hours may be consecutive, which is essential since the duration of high risk events can last several hours. This means that resources must be able to

47 Texas House of Representative Committee on State Affairs at 2:53:52 (Dec. 5, 2022) (available at: https://tlchouse.granicus.com/MediaPlayer.php?view_id=46&clip_id=23711) (explaining that Brazos Electric Cooperative's bankruptcy was driven by the cost of Winter Storm Uri, that the Talon Energy Supply bankruptcy was driven by Talon's natural gas hedging strategy during Winter Storm Uri, and that the Panda Temple Power bankruptcy was driven by exposure in bilateral contracts during Uri).

perform across these hours (and not just for a single hour). The Commission should align the award of PCMs to this actual need to ensure that the resources that qualify and receive PCM payments can actually address ERCOT's operational needs. In that vein, the Commission and stakeholders should work with ERCOT to determine the appropriate number of hours, taking into consideration ERCOT's reliability needs, the incentives that will be created by any market design proposal it is implementing, and the impact on costs to consumers.

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?

See response to Question 4.

6. Would a voluntary forward market for generation offers and a mandatory residual settlement process for LSE procurement provide additional generation revenue sufficient to incentivize resource availability in a way that improves reliability?

TIEC is still developing its position on this issue. However, any resource awarded PCMs must show that it can perform or those payments should be returned to customers.

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

TIEC is still considering this issue.

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 l-in-10 LOLE or another reliability standard? If so, what product or service should be considered?

TIEC does not support the PCM and does not believe the 1-in-10 LOLE is appropriate. TIEC recommends that other approaches be adopted instead of the PCM, as set forth in these comments.

9. If implementing a short-term design as a "bridge" delays the ultimate solution, should it be considered? Is there an alternative to a bridge solution that could be implemented immediately, using existing products, such as a long-term commitment to buy the additional 5,630 MW of Ancillary services necessary to achieve the l-in-10 LOLE reliability standard?

See answer to Question 8.

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

As discussed above, the PCM will cost consumers at least $5.7 billion per year compared to the current energy-only market. Although the E3 Report claims the PCM will only have an incremental cost of $460 million per year, that comparison is based on an unrealistic scenario where the energy-only market sees massive thermal retirements creating unrealistic scarcity pricing, but those anticipated retirements are driven by E3's modeling assumptions. Notably, the PCM could create a "worst case scenario" for consumers by forcing them to pay a clearing price for energy and another clearing price for energy, with the risk of extremely high scarcity pricing for both, as discussed above.

11. What is the fastest and most efficient manner to build a "bridge" product or service, such as the BRS, in order to start sending market signals for investment in new and dispatchable generation, while a multi-year market design is implemented by ERCOT? Please provide specific steps

See answer to Question 8.

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?

TIEC is still analyzing this issue.

III. CONCLUSION

TIEC appreciates the opportunity to provide these comments and looks forward to further discussion to develop more effective and less costly reforms to the ERCOT market.

Respectfully submitted,

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ATTORNEYS FOR TEXAS INDUSTRIAL ENERGY CONSUMERS

PROJECT NO. 54335

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

TEXAS INDUSTRIAL ENERGY CONSUMERS' EXECUTIVE SUMMARY

- Reliability is TIEC's number one priority, but the Commission should purse it in an economically responsible way, rather than creating an energy tax or massive mandatory wealth transfer from customers to generators with no guaranteed benefit.

- ERCOT does not have an installed capacity shortage. As noted in the E3 Report, the problem is operational uncertainty surrounding the availability of renewable resources and forced outages of thermal generation across times of high net peak load.

- The E3 Report drastically overstates the need for market overhauls by incorrectly modeling the prospective performance of ERCOT's energy-only market. Notably it overstates anticipated thermal generation retirements, fails to accurately model the ORDC, and does not model new entry that would result from scarcity pricing, which manufactures a capacity shortage and high prices.

- Importantly, none of the solutions in the E3 Report will guarantee new generation development. The only way to ensure new generation is by procuring it directly.

- While it is difficult to comment on the PCM proposal because the characteristics continue to shift, it is an expensive, complex, and ineffective solution. Functionally, it is a capacity market awarded on a backwards-looking basis. As such, it will likely degrade performance incentives without guaranteeing any new dispatchable generation. It will also take years to implement, which will likely chill investment in the near-term.

- Instead of the PCM, TIEC recommends the Commission adopt the Dispatchable Reliability Reserve Service, which is a targeted day-ahead ancillary service product that will be sized appropriately to address the current and expected variability in ERCOT's net peak load. This would create new price signals for new and existing dispatchable resources and is performance-based.

- If the Commission decides to move forward with the PCM, it would be improved by (1) incorporating an economically rational target reserve margin of expected un served energy, rather than an event-based LOLE; (2) assigning credits based on "net peak load" when reliability risks are the highest; (3) allowing participation by any resource that can provide capacity during times of highest net peak demand; and (4) eliminating the admittedly inefficient and costly changes that have been made to the ORDC curve.