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Received - 2021-12-10 11:39:51 AM
Control Number - 52373
ItemNumber - 301

PUC PROJECT NO. 52373

REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

TEXAS INDUSTRIAL ENERGY CONSUMERS' COMMENTS

I. INTRODUCTION

For more than two decades, ERCOT has been a model for competitive electric markets around the world. Our unique, efficient market design has driven down costs while delivering equal or better reliability than other markets. Under SB 3, the Legislature recognized that Winter Storm Uri was not a failure of our competitive market—but that there are issues that need to be addressed to ensure reliability going forward. Among those important issues were weatherization, fuel security, and ensuring we have generation ready and available for all conditions as our resource mix evolves. Through SB 3, the Legislature ***specifically*** directed the PUC to address generation availability issues through "ancillary and reliability services" that build on our current market design. Notably, the Legislature ***did not*** direct the Commission to implement a forward capacity mandate. In fact, legislation proposing this approach was filed, heard, and rejected in favor of SB 3.[1] TIEC urges the Commission to honor the Legislature's intent and build from of our successful competitive market, rather than moving toward a bilateral capacity mandate.

TIEC supports many of the Phase I initiatives, even though they will increase consumer costs. The Operating Reserve Demand Curve (ORDC) changes are still limited to "tight" conditions, but will produce higher prices at higher reserve levels and significant "headroom" payments for even more megawatts of available reserves. Customers will also bear the additional costs of the new and expanded ancillary and reliability services needed to manage operational variability, including the additional procurements that began over the summer. These Phase I changes would constitute an unprecedented overhaul of the ERCOT market in any prior period. However, they are generally consistent with our competitive market design, and should improve reliability for customers without undermining the critical role of ***energy prices*** in incentivizing both operational reliability and long-term resource adequacy.

As to the Phase II changes, TIEC is still not convinced these more aggressive measures are justified or necessary, and is concerned about "pancaking" changes that have duplicative or overlapping impacts. ERCOT's latest CDR shows a 29% reserve margin this summer, and over 30% for the next five years. These margins have not been seen for a decade and show that we do not have an installed capacity problem. While much of this generation is intermittent, it is unclear that we cannot manage this intermittency with existing tools and those being proposed in Phase I.

[1] *See* House Bill 4378, "Relating to the supply of power and the financial stability of the competitive wholesale and retail electricity markets."

With this context, TIEC views Commissioner Cobos' Backstop Reliability Service (BRS) as consistent with the intent of SB 3, and a "middle ground" of the longer-term reserve service proposals from TIEC, NextEra, LCRA, Luminant, and others. While issues of scope and eligibility remain, the general BRS concept appears workable and generally consistent with ERCOT's market design. Similarly, the general framework of the Dispatchable Energy Credit (DEC) proposal put forth by Commissioner McAdams offers a targeted approach to providing additional incentives for new dispatchable capacity as required by SB 3.[2] DECs have the potential to drive additional revenues toward new investment with needed performance capabilities. DEC revenues can supplement market price incentives during net peak load conditions, as well as higher future ancillary service revenues. Incentivizing incremental generation investment, the DEC proposal is more targeted and effective than an overall forward capacity mandate.

TIEC continues to oppose all iterations of an "LSE Obligation," which involve mandated forward procurement of capacity sufficient to meet total system demands. This expensive, administratively complex approach has been tried and failed in other jurisdictions. TIEC urges the Commission to remain dedicated to the competitive principles that have made our market successful without pivoting to the type of centralized planning we have seen in California, the Midwest, or the northeast.[3] Texas has an opportunity to address the challenges of our evolving grid in a uniquely "Texan" way, and we should continue to chart our own course.

II. CLARIFICATION ON PHASE I

The draft blueprint contemplates nodal settlement for "demand response." Demand response refers to many different things, including passive price response by loads outside any reliability or ancillary services. Nodal pricing for demand response makes sense in some cases (for example, Controllable Load Resources (CLRs)), but TIEC is concerned the memo's wording might be misinterpreted as requiring ***all loads*** to change to nodal settlement. This would be a major policy change that is disruptive to the market, creates winners and losers among customers in different regions, and undermines existing retail products and hedges. TIEC recommends clarifying this language to say: "Pursue market modifications and technical measures to improve transparency of price signals for load resources, such as allowing locational marginal pricing (LMP)~~changing demand response pricing from zonal to locational marginal pricing (LMP).~~"

III. COMMENTS ON PHASE II PROPOSALS

1. Refinements to BRS.

According to the draft blueprint, BRS resources would not be allowed to participate in energy or ancillary services markets during their obligation period. This feature would make BRS

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[2] *See* SB 3, "The Commission shall…(2) evaluate whether additional services are needed for reliability in the ERCOT power region while providing adequate incentives for dispatchable generation."

[3] *See, e.g.*, https://www.utilitydive.com/news/california-markets-in-the-lone-star-state-texas-regulators-consider-quasi/608695//.

most suitable for older, less economic units that are unlikely to be "in the money." As a result, BRS would primarily (a) incentivize units that are approaching retirement to stay in the market and (b) "juice" market revenues for other resources. BRS should be procured no more than one year in the future for one-month obligation periods, and procurement should be for MWs needed to "fill the gap" in seasonal dispatchability—***not the entire market***. Procuring this reliability service closer to real-time provides more certainty around quantities and LSE allocations, which gives market participants flexibility to manage their positions. Properly structured, BRS would function like a longer-lead-time ancillary service, consistent with the intent of SB 3. Allocating BRS based on each LSE's demand during net peak load periods will also provide strong demand response incentives to further support reliability. These are all positive features of the proposal.

Part of the BRS design is to hold resources "out of the market." TIEC agrees with Commissioner Cobos's memo that this does not necessarily mean they need to be priced at the HCAP. Rather, an appropriate price floor (or other mechanism) that puts BRS units behind other market units will provide appropriate pricing and investment signals without artificially setting prices at the cap—which is not economically justified and can have profound consequences, as the Commission is well-aware.

TIEC suggests two clarifications to the BRS to ensure appropriate quantities are procured and to improve flexibility for participating resources:

- ***Monthly rather than seasonal obligations would maximize participation and reduce costs for customers.*** Committing to stay out of the market for several months and forego potential energy or ancillary service revenues may be a deterrent even for older generators who are rarely deployed. Procuring BRS for one-month obligation periods will likely attract more units at a lower cost for customers.
- ***Procurement should not be tied to the SARA at this time.*** As ERCOT has explained, the SARA is a scenario analysis that illustrates a hypothetical range of often extreme potential outcomes.[4] The SARA is alarmist by design, and is not a projection of what is likely occur or even 10% likely to occur. It excludes a number of verified, available resources like ERS and Load Resources. The Commission should retain flexibility on how seasonal variability will be determined for BRS.

2. The DEC proposal could effectively incentivize new generation.

BRS would appear to primarily pay units that are closer to retirement, and "juice" real-time energy prices for all other market generators. Commissioner McAdam's DEC proposal, in contrast, would specifically target ***new***, ***incremental*** investment in certain types of resources needed to maintain reliability. The DEC proposal envisions specific performance requirements for eligible resources that will essentially target newer investment that is suitable to address system ramping needs. Again, TIEC believes that new and expanded ancillary services will also provide

[4] *Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2021/2022*, ERCOT (Nov. 19, 2021) (available at: https://www.ercot.com/files/docs/2021/11/19/SARA_Winter2021-22.pdf).

strong incentives for these resources, so the DEC should be viewed as a supplemental incentive. DEC resources should not be held of the market, so DECs will be more attractive to newer investments. Two features of the DEC proposal as outlined in the blueprint are problematic:

- ***Alternative Compliance Payments (ACP) for DECs should not be at Cost of New Entry (CONE).*** Setting the ACP at CONE was discussed for the first time at the last work session and is inconsistent with the DEC design. DECs should encourage new, nearly economic dispatchable generation, so the ACP should be a fraction of CONE, not a full capacity payment. If the PUC mandates 4,000 MW of DECs, for example, the ACP paid by the market for full compliance could be $350 million per year.[5] An ACP is meant to protect customers from exorbitant costs if a mandate cannot be cost-effectively achieved, similar to the RPS.[6]

- ***DEC payments should be paid to capacity (MWs) cleared in the annual DEC procurement—not to all energy (MWhs) generated by eligible resources.*** The RPS standard converts an annual capacity goal into a MWh allocation to LSEs. However, renewable generation is typically price-taking and produced as available. Awarding DECs on a MWh basis will not work well because eligible resources (like peakers) will not run when intermittent generation performs at expected levels, Payments to DEC resources should be based on the MWs of awarded capacity, and the costs can then be allocated on a load ratio share to customers based on their contribution to net peak load periods, per the blueprint.

Similarly, some versions of the DEC proposal appear to contemplate only paying DECs to MWs that clear in the DAM energy or ancillary service markets. In many instances, however, the DEC resources won't be needed and would not clear in these markets even if offered. Instead, DEC resources should have a must offer requirement, but should be paid based on a capacity award and not based on how often they actually clear for energy or ancillary services.

3. An "LSE Obligation" (as a full bilateral capacity mandate) should not be pursued.

More than two decades of engineering, economic, and legal expertise from stakeholders, legislators, and regulators with a deep commitment to Texas have been invested in designing an electric market that is uniquely Texan. Discarding ERCOT's fundamental market design in favor of a forward capacity mandate is not justified or necessary, and will only increase costs without improving reliability for customers. This is true of both centralized and decentralized (bilateral) forward capacity mandates. Independent economists hired by ERCOT and the PUC have stated that an LSE Obligation, as envisioned by the E3 proposal and similar iterations, is a decentralized capacity market. As Dr. Patton observed, "When you establish a minimum capacity requirement you are essentially establishing a capacity market, even if it's a bilateral market."[7] Similarly, "[i]n

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[5] 4,000 MW multiplied by the 2019 ERCOT CONE of $88,500/MW.

[6] The RPS rule provides an alternative compliance payment of $50/MWh.

[7] *See* October 14, 2021 Work Session Part 2 at 37:39.

a capacity market, like the E3 proposal, you're giving [generators] money that you're not going to take back if they don't perform."[8] Brattle opined, "What's the demand and how resources are accredited is all fairly similar to a capacity market. It's just not a centralized auction it's bilateral... If it's purely bilateral you cannot, I don't think, satisfactorily mitigate the structural market power that exists [from Gen-Tailers]."[9]

California's experience, among others, demonstrates that an LSE Obligation will not put steel in the ground or improve reliability.[10] As E3 acknowledged, the California market has an LSE Obligation called the "Resource Adequacy Program."[11] The Resource Adequacy Program, adopted in 2004, requires all LSEs to procure capacity based on forecasted needs in monthly and annual filings.[12] Even though California began requiring all LSEs to procure capacity for their full expected demand in 2006, California has issued over 45 conservation alerts since 2012 and instituted rolling blackouts during the summer of 2020.[13] California's LSE Obligation has not improved reliability in over 15 years—it has only increased costs. Similarly, LSE obligations in SPP and MISO and the capacity market in PJM have not prevented outages during extreme weather—even though these markets are ***also*** largely populated by vertically integrated utilities.

TIEC also remains greatly concerned about retail consolidation and market power under an LSE obligation, as well as the potential implications of stacking an LSE obligation on top of other pending market design changes. If customers will be required to make annual capacity payments to the vast majority of existing and new generation under an LSE Obligation, then the Commission should substantially reduce other administrative revenue streams to provide a fair value to customers, as observed by Commissioner Glotfelty. These "bells and whistles" are no longer appropriate in a market where generators are not primarily relying on energy prices to earn profits and justify investment. An LSE Obligation will thus also subsume both BRS and DECs as the capacity payments become the primary revenue stream for all generators.

Finally, under an LSE Obligation, the Commission will likely need to adopt restrictive limitations on each REP's share of the retail market, each generator owner's share of the wholesale market, and perhaps how much generation can be owned by "gen-tailer" affiliates. This is imperative to curb market power abuses under an LSE Obligation. These are just a few of the major changes that the Commission must be considered if it transitions away from the current market design.

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[8] *See id.* at 2:06:28.

[9] *See id.* at 2:49:22.

[10] *See, e.g.* Utility Dive "California Markets in the Lone Star State? Texas Regulators Consider 'Quasi-Capacity Market' System" (https://www.utilitydive.com/news/california-markets-in-the-lone-star-state-texas-regulators-consider-quasi/608695/).

[11] Project 52373, E3 Load Serving Entity Reliability Obligation Proposal at 15 (Sep. 30, 2021).

[12] California Public Utility Commission, Resource Adequacy Homepage (https://www.cpuc.ca.gov/RA/).

[13] *See* CAISO News Releases (http://www.caiso.com/about/Pages/News/NewsReleases/Default.aspx).

Respectfully submitted,

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PUC PROJECT NO. 52373

REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

<u>TEXAS INDUSTRIAL ENERGY CONSUMERS' BLUEPRINT COMMENTS</u>

<u>Executive Summary</u>

- **<u>Overview:</u>** SB 3 gave the Commission specific direction on market changes to improve generation availability issues. These concerns should be addressed through "***ancillary and reliability services***" and "new ***services*** that ***provide adequate incentives for dispatchable generation***. Market changes should complement our market design, not supplant it.

<u>Phase I</u>

- TIEC agrees with many of the Phase I initiatives outlined in the draft blueprint, even though they will likely increase consumer costs.
- Phase I measures are generally consistent with SB 3 and complement our market design. They should support operational reliability and promote long-term resource adequacy,
- <u>Phase I Demand Response Pricing</u>: TIEC recommends clarifying the language for Phase I on nodal settlement for loads to avoid an implication that all loads must change to nodal settlement. This would be a major policy change, and does not appear to be the intent.

<u>Phase II</u>

- TIEC is not convinced that Phase II's more extreme measures are necessary and has concerns about adopting too many overlapping market changes at once.
  - <u>Backstop Reliability Service (BRS)</u>. TIEC is not opposed to the concept of BRS, if necessary. BRS functions like a longer-lead-time ancillary service, consistent with SB 3. TIEC recommends two clarifications:
    - Obligations should be monthly to increase participation, reduce costs.
    - Commission should retain flexibility on how it defines seasonal variability for BRS and should not tie it to the SARA without significant reforms.
  - <u>Dispatchable Energy Credit (DEC)</u>. TIEC values that DECs are meant for new generation, not be a capacity payment all dispatchable resources in the entire market.
    - DEC payments should be paid to capacity (MWs) cleared in the annual DEC procurement—not based on energy (MWhs) generated by eligible resources.
    - Alternative Compliance Payments (ACP) for DECs should be a fraction of the Cost of New Entry (CONE), not a full capacity payment. DECs should be an additional incentive, not a full capacity mandate.
  - <u>"LSE Obligation."</u> As a full bilateral capacity mandate, this option should not be pursued.
    - It is inconsistent with SB 3; expensive, bureaucratic, and has not worked elsewhere.
    - Major changes needed to address market power/retail consolidation. Likely need more restrictive limits on retail market shares and generation ownership.