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

TEXAS INDUSTRIAL ENERGY CONSUMERS' COMMENTS ON COMMISSION QUESTIONS

I. INTRODUCTION

The electricity market—including the wholesale market—exists to provide reliable electricity to customers at a reasonable cost. When evaluating market design changes, the Commission should always ask what reliability benefit a particular change will produce for customers, and at what cost. In addition, before making major changes to the market design, the Commission should clearly define the specific problem that needs to be addressed and tailor any changes to that specific issue.

On behalf of the state's largest electric customers, Texas Industrial Energy Consumers (TIEC) prioritizes three key principles in evaluating the wholesale market design:

(1) <u>Generation investment risk should be borne by competitive power generation companies, *not customers*</u>. This was a central tenet of deregulation. Requiring customers to directly fund capital investment in competitive power plants would negate the "benefit of the bargain" for customers in deregulating. In a regulated model, customers pay for capital investment in power plants directly, but they buy the plants at actual cost (plus a return) and receive the energy produced at cost. In a competitive market, customers pay high clearing prices to all units to incentivize investment. In exchange, competitive generators bear the capital investment risk.

(2) <u>High wholesale prices should align with periods of low supply compared to demand</u>. Concentrating high prices during periods of system need provides a strong financial incentive for generators to perform *when they are needed most*, and elicits efficient demand response from customers. Shifting additional market revenues to off-peak periods dilutes generator performance incentives, increases costs to customers with no corresponding reliability benefit, elicits inefficient and unnecessary demand response—particularly from the business and industrial community—and can cause large loads to site in other regions. This is at odds with the state's growth objectives.

(3) <u>If specific performance characteristics are needed for system reliability, resources should be procured to provide those capabilities on a competitive, technology-neutral basis.</u> Reliability needs should be objectively defined, and all eligible resources should compete to fulfill those needs—including demand response, generation, and batteries. This maximizes competition and provides the best value to customers. The Commission should not carve out revenue streams for a particular type of resource by technology or fuel type. In some instances, only certain technologies will be able to meet certain reliability needs, but procurement should be based on the reliability need, not the resource type.

With these objectives in mind, TIEC's responses to the Commission's questions are below.

II. COMMENTS ON COMMISSION QUESTIONS

1. What specific changes, if any, should be made to the Operating Reserve Demand Curve (ORDC) to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market (DAM). Should that amount of ORDC-based dispatchability be adjusted to specific seasonal reliability needs?

Based on experience, TIEC is skeptical that manipulating the "shape" of the ORDC will have any real impact on current investment patterns. Proposals to make the ORDC "flatter" are primarily designed to expand and extend the "tail" of the ORDC. This artificially increases prices when reserves are sufficient for reliability (*i.e.*, more of the time), and divorces real-time revenues from performance during periods of shortage. This shifts financial performance risk from generators to customers, increases total costs, and may actually harm overall reliability. If the Commission is concerned about the level of risk in the current ORDC design, TIEC is open to reducing the Value of Lost Load (VOLL) and, correspondingly, the System Wide Offer Cap (SWCAP). TIEC is also open to discussing whether it makes sense to pay the ORDC to only a subset of resources. In addition, the Commission should reinstate seasonal ORDC curves to more accurately reflect reserve variability in different times of the year. These seasonal variations have become a driving factor in system reliability. This is addressed in further detail below.

i. The existing ORDC over-values reserves, and the additional revenue to generators has not changed investment trends.

The ORDC was designed to pay resources for providing real-time operating reserves. It was the Commission's solution to the so-called "missing money problem,"[i] which is the theory that paying generators solely based on the marginal offer of the last unit needed to serve load does not incentivize additional "reserves" for contingencies. While the ORDC is a form of administrative scarcity pricing (and has several flaws as discussed below), it is based on economic principles that should be respected in any future changes. From the consumer perspective, the ORDC should not be turned into an arbitrary "revenue sufficiency" tool to force wealth transfers from customers to generators to achieve a specific level of capital investment, but should continue to value reserves based on economic principles.

In theory, the ORDC values reserves based on two inputs: (A) the value of lost load (VOLL), which is the theoretical price where customers prefer to lose electricity than to pay any more (currently set at $9,000/MWh), and (B) the likelihood of rotating outages in the next hour based on historical variability in operating reserves. Under this design, when reserves are ample, the probability of firm load shed is low and the ORDC value should approach $0. As reserves are depleted, load shed probability increases, and ORDC pricing should increase until it reaches the VOLL—which should theoretically coincide with firm load shed (*i.e.* when the probability is 100%). However, the current ORDC was designed with several conservative adjustments, such that it already requires customers to over-pay for operating reserves.

First, the ORDC sets prices at $9,000/MWh (VOLL) long before firm load shed actually occurs. This occurs at a "minimum contingency level" (MCL) of 2000 MW of operating reserves.[ii] Firm load shed ***actually*** begins at around 1,100 MW of PRC, so this administrative assumption causes the ORDC to over-value reserves by shifting the entire curve to the right by 900 MW. Second, in 2019, the Commission made two additional changes: (1) the ORDC curve was shifted by half a standard deviation (in two "steps" over two years) to overstate the probability of reserves dropping below the MCL in the next hour, which increases ORDC pricing in periods with relatively higher reserves, and (2) the 24 "seasonal" ORDC curves designed to reflect the variability of reserves by time of day and by season were collapsed into a single curve, which had the effect of overstating reserve variability in the summer and *understating* it at all other times of the year.[iii] These two changes added significant costs to the market during the summer of 2019, when reserve margins were lower. In 2019, these changes contributed to wholesale market prices increasing by 40% relative to 2018, adding an estimated $1.4 to 1.6 billion in market revenues.[iv] The changes similarly caused Peaker Net Margin (PNM, a measure of generator profits) to reach the highest level ever observed until Winter Storm Uri, despite very low natural gas prices.[v]

In spite of these adjustments to the ORDC, there has been no material change in investment patterns. Because the ORDC pricing does not distinguish between dispatchable and non-dispatchable resources, the 2019 changes only increased the incentive to investment in technologies that were already preferred by investors (*i.e.*, wind and solar generation). There have been minor uprates of existing thermal units, unprovable claims that existing units "stuck around" as a result of the changes, and significant expansion of smaller-scale distributed gas and behind-the-meter generation. However, since 2018, ERCOT has had a net loss of roughly 1,700 MW of thermal generation facilities,[vi] and a net increase of 2,350 MW of solar and 3,571 MW of wind.[vii] In the December 2020 CDR, planned solar for 2022 was estimated at 15,389.5 MW.[viii] Since 2013, just prior to ORDC implementation, ERCOT has had a net loss of 740 MW of thermal generation,[ix] and a net gain of 14,537 MW of wind and 3,761 MW of solar.[x] This data shows that customers have paid more through the ORDC since 2014, and particularly since 2018, but there has been no real change in the outcome—investment is still predominantly in intermittent generation. This is only somewhat driven by economics (these resources earn higher margins) and largely driven by external factors such as federal tax incentives and Environmental, Social and Governance (ESG) investment trends. Given this history, TIEC does not believe that additional changes to make the ORDC "richer" or provide more off-peak revenues will accomplish anything besides increasing prices and shifting risk from existing generators to customers.

ii. Price volatility in ERCOT is driven by the variability of intermittent generation—not the shape of the ORDC.

One of the arguments for adjusting the ORDC is to make pricing "less volatile." First, only a very small number of sophisticated business consumers are exposed to real-time pricing. The vast majority of customers have at least partially hedged retail contracts or are able to manage their risk individually in other ways (like reducing demand). Second, and more importantly, most generator revenues ***are not earned in the real time market***, but through bilateral contracts and hedging activity. The narrative that generators "don't get paid" unless the system is in crisis is absolutely incorrect and misguided. Both ERCOT and the IMM testified during the legislative session that only an estimated 15-20% of energy transacted in the real-time market is actually exposed to real-time prices, with the rest hedged either in the DAM or bilaterally. Long-term bilateral agreements include a risk premium based on the ***potential*** for scarcity pricing to occur, and a particular counterparty's level of risk aversion. Because of this, scarcity ***does not actually have to occur*** for generators to receive premium pricing in bilateral agreements. Instead, high real-time prices act as a steep penalty for generators who fail to perform and have to replace contractual obligations in the spot market. This is why it is predominantly generation owners seeking to make wholesale pricing "gentler," not customers.

In addition, price volatility in the real-time market is not driven by the ORDC curve. The ORDC begins increasing energy prices relatively far from any actual reliability event. Rather, the volatility of real-time prices is driven primarily by unpredictable output from intermittent generation. In recent years, reliability events and high prices have not been tied to the highest demand on the ERCOT system, but the days when demand is relatively high ***and renewable generation output is low***.[xi] Except for Winter Storm Uri, which was caused by several coincident factors, operational uncertainty around intermittent generation has been the primary driver of "scarcity" conditions over the last few years. As the IMM observed after the summer of 2019, when Energy Emergency Alerts (EEAs) were required in August, "EEA conditions were not on the highest load days… Net Load

(Load-Wind) is a better predictor of high prices."[xii] This outcome stems from three essential problems: (a) ERCOT is now relying on intermittent generation to serve load, (b) the significant intermittent fleet makes it challenging for both dispatchable generators and ERCOT to accurately predict real-time operating conditions, and (c) intermittent resources do not respond to market conditions or price signals. These are the issues that need to be managed—not the shape of the ORDC.

Importantly, if high prices begin to occur more regularly and predictably due to this intermittency, it should create an opportunity and price signal for investment in resources to "fill the gap" ***without*** the need for additional market design changes or intervention. TIEC believes this is occurring today, but primarily through small-scale peaking units, distributed generation, and demand response. If the Commission believes additional action is needed to encourage dispatchable investment, the most targeted and efficient approach is through the ancillary services market—not the ORDC.

iii. Reasonable Changes to the ORDC.

For the reasons described above, TIEC does not believe "shifting" or "flattening" the ORDC will address perceived issues with the existing market design. That being said, TIEC is open to other reasonable changes to the ORDC:

Seasonal ORDC Curves. The Commission should reinstate "seasonal" ORDC curves. Recent experience has demonstrated that seasonal variability in reserves has become a significant reliability factor. The current ORDC curve assumes that reserve variability is the same year-round, which is ***simply not true***. This assumption overstates variability (over-values reserves) for peak summer conditions, when maximum dispatchable generation is online, and *understates* variability (under-values reserves) during off-peak conditions, when the grid relies more on intermittent generation to serve load. Seasonal ORDC curves would provide better pricing and commitment signals based on the risk of major swings in operating reserves by season. It is probably unnecessary to reinstate all 24 curves from the original ORDC design. TIEC's preference would be eight total curves, with one for "on-peak" and one for "off-peak" hours during each of the four seasons. But, even two distinct curves for on-peak (summer) and off-peak (all other periods) would send more accurate investment and pricing signals than the current design.

VOLL Reduction. TIEC did not advocate for the current $9,000/MWh VOLL value when it was originally established in 2012. TIEC originally supported a cap of $4,500/MWh[xiii] based on the pre-ORDC market design, which triggered the SWCAP more frequently. As the ORDC was implemented, TIEC indicated that a VOLL in the $6,000/MWh range would be reasonable. ERCOT commissioned a study from London Economics in 2014 to find objective support for a particular VOLL.[xiv] However, the report was very clear that it "does not – and cannot – provide a single VOLL estimate for the ERCOT region."[xv] The report provided a number of data points that could have supported a wide range of VOLL choices. TIEC is not actively advocating to change the existing VOLL, but believes economic data would support a lower VOLL to reduce the most extreme financial risk in the market, if that is the Commission's policy choice. The $9,000/MWh VOLL has actually worked quite well since 2012, and there have been no significant market default events until Winter Storm Uri. The issues with the Low System-Wide Offer Cap (LCAP) trigger that contributed to Winter Storm Uri's default event have largely been addressed by revisions to PUC Subst. R. 25.505, and may be further mitigated by the directives from SB 3 on emergency pricing. However, if the Commission seeks to reduce perceived pricing risk, a lower VOLL of $6,000/MWh would be reasonable.

Paying the ORDC to a Subset of Resources. The Commission should evaluate whether the ORDC should be paid only to resources that provide reserves that ERCOT can call upon when needed—*i.e.*, dispatchable resources. The purpose of the ORDC is to value and incentivize investment in operating reserves. Arguably, intermittent resources that cannot be dispatched to serve system needs do not provide "reserves," only as-available energy. Intermittent resources also do not respond to market prices, so sending an ORDC pricing signal to these resources does not change their behavior. Requiring customers to pay the ORDC price adders to these resources does not increase reliability or reserves, just total costs. Therefore, if the Commission seeks to use the ORDC as a means of increasing revenues for dispatchable resources, the ORDC should be targeted only to resources that provide reliable operating reserves and not the entire market. TIEC believes this potential approach merits further discussion, but also recognizes there may be unintended adverse consequences of bifurcated energy pricing. In particular, it would complicate energy transactions to have two different energy clearing prices, and TIEC does not have a full picture at this time of how SCED might be impacted. These issues should be explored further.

TIEC addresses the proposal to pay the ORDC only to DAM participants in Question No. 2.

2. Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market?

a. If so, how should that minimum commitment be determined?

b. How should that commitment be enforced?

TIEC understands that a mandatory DAM is being considered to potentially "firm up" intermittent generation by forcing it to commit to an output level and bear financial responsibility for failing to meet that commitment in the real-time market (RTM). In theory, this would force intermittent generation to mimic dispatchable resources that contract bilaterally or participate in the DAM.

However, it is not apparent that mandatory DAM participation would be effective in addressing intermittency. The fundamental reliability concern with intermittent generation is not day-to-day variability, but the disconnect between market investment signals and actual reliability levels given the uncertainty of intermittent output. When the abundant intermittent generation supply in ERCOT shows up, the system is replete with supply-side resources and the market appropriately signals that no new investment is needed. However, when this intermittent generation fails to show up, it can cause reliability events ***even if*** performance matches DAM expectations. The issue that needs to be addressed is really variability from seasonal or annual average output levels, not the DAM. As a result, it is not clear that requiring intermittent generation to "firm up" to the DAM will make a substantial difference in reliability or investment incentives.

The sub-questions suggest that mandatory DAM offers might not be based on ERCOT's wind or solar DAM forecasts, but minimum requirements on intermittent generators. Importantly, ERCOT's aggregated wind and solar forecasts have historically been much more accurate than individual resource forecasts. Requiring intermittent resources to submit individual forecasts could substantially increase uncertainty in the DAM clearing results, which could in turn make commitment decisions for dispatchable resources even more challenging. TIEC is open to further discussions on this potential approach, but believes that implementation may be difficult.

3. What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated?

TIEC appreciates the discussion around potential ORDC changes and concepts like a mandatory DAM; however, TIEC believes that procuring additional ancillary services is the most direct and cost-effective way to address the variability of intermittent generation. Through additional ancillary service procurements, the Commission can ensure that any incremental costs to customers go directly to resources with the desired performance characteristics (*i.e.*, dispatchability), and do not incidentally drive additional intermittent development like the solar boom following the 2019 ORDC shifts. In many respects, ERCOT has already started repurposing existing ancillary services to serve this function, with increased Non-Spinning Reserve Service (NSRS) and Responsive Reserve Service (RRS) procurements beginning in July. Rather than doing this on an *ad hoc* basis with existing tools, and without sufficient notice for the market to hedge and respond, TIEC recommends creating a supplemental service specifically for this "firming" purpose. With sufficient market notice and predictability, this type of "firming" service would provide a strong incentive for dispatchable investment in a way that minimizes cost increases for customers.

This "firming" service should be aimed at managing annual or seasonal "net load variability," which TIEC defines as the combined variability of intermittent generation and demand relative to annual or seasonal averages. ERCOT already has robust reserve margins, so mandating anachronistic reliability standards that are focused on overall installed capacity levels (for example, the dated "1-event-in-10-years" standard) will only increase consumer costs without addressing the specific reliability needs of our market. Instead, ERCOT should study the variability of both load and intermittent generation by season, and procure supplemental ancillary services (beyond what exists today) to ensure that sufficient thermal generation will available to address this variability. Additional market revenues for these services will go ***directly*** to dispatchable resources, and will provide the lowest-cost solution for customers. If insufficient dispatchable generation is available to meet reliability needs through this new ancillary service, a penalty curve can be imposed just like for other ancillary services, sending a strong price signal for additional investment. This "firming" ancillary service would be complementary to TIEC's proposed seasonal ORDC curves, which will provide ***energy*** market signals for reserves during periods of high variability.

Importantly, implementing a "firming service" should begin with an objective evaluation of the magnitude the actual problem, which remains ill-defined. TIEC began expressing concerns about relying on wind to serve load years ago, following the build-out of transmission to Competitive Renewable Energy Zones (CREZ). However, as renewable penetration in ERCOT has grown over time, the diversity in technologies and geography has mostly caused overall system variability to be lower than TIEC anticipated. Historically, net load variability has primarily caused conservation alerts and EEA1 declarations, and has *never* resulted in firm load shed. ERCOT has generally been able to manage the variability with existing tools, which includes existing ancillary and reliability services. New technologies and market-driven solutions should be expected to further reduce this variability over time without the need for market intervention. To that end, procuring additional ancillary services based on actual variability data would mean that ***if*** the market is able to solve this reliability issue on its own, ancillary service procurements can proportionally be reduced along with consumer costs. As a result, "firming" ancillary service to address net peak load variability provides a targeted, cost-effective way to actually improve reliability. As the revenue streams from this additional ancillary service becomes known and predictable for investors, the market should expect additional dispatchable investment.

TIEC is still evaluating the appropriate allocation of a net load variability service. There are cost-causation arguments for allocating both this new ancillary service and existing services (particularly NSRS) to both customers and intermittent generation resources. However, the mechanics of allocating ancillary services to generators based on megawatts ***not*** provided is complex, and TIEC is still evaluating whether this approach merits the complexity. Particularly if other changes are made to focus ORDC revenues on dispatchable generation, TIEC would need to further consider whether direct allocation to intermittent generation is necessary. TIEC recommends that the Commission move forward with creating a net load "firming" service but continue discussions on the allocation process as the service is developed and causation data can be better evaluated.

In addition to ancillary services for net load variability, TIEC also supports procuring ancillary services to address extreme cold and heat, as contemplated by SB 3. These ancillary services would need to be based on data regarding forced outage rates and derates during extreme weather conditions, and would need to be able to perform over an extended period (longer than an hour). TIEC looks forward to addressing the specifics of these services as they are implemented pursuant to SB 3.

4. Is available residential demand response adequately captured by existing retail electric provider (REP) programs? Do opportunities exist for enhanced residential load response?

The inelasticity of residential demand has long impeded a fully functioning competitive market. Residential customers are not typically exposed to price and have little to no incentive to actively manage their electricity consumption. For these reasons, REPs and other LSEs have been placed in the role of facilitating residential demand response, which can be one of the most cost-effective "hedges" if residential customers will participate. REPs/LSEs must create a value proposition for residential demand response by offering rebates or other financial benefits in exchange for demand response. TIEC believes this remains an untapped market resource, but recognizes that there are often political, practical, and cost limitations in developing this resource. Residential demand response is truly the "last frontier" of a competitive electric market. TIEC believes that REPs and LSEs are appropriately incentivized to develop this resource under the existing market design.

5. **How can ERCOT's emergency response service program be modified to provide additional reliability benefits? What changes would need to be made to Commission rules and ERCOT market rules and systems to implement these program changes?**

At this time TIEC does not believe expanding Emergency Response Service (ERS) is necessary or cost-effective. While the ERS program has been valuable in supporting reliability, other pending market design changes, along with the requirements in SB 3, are also likely to impose cost increases for consumers and will have greater reliability impacts. ERS is currently subject to a $50 million annual cost cap under P.U.C. Subst. R. 25.507(b)(2). TIEC does not believe this cap should be modified at this time. TIEC would potentially support changes to the program to allow additional loads to participate within this existing cost cap.

6. How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?

TIEC does not have further recommendations on this question beyond the response to Question No. 3. TIEC is not aware that there are currently deficiencies in the market's ability to provide inertia, voltage support, of frequency response. These services are provided by existing dispatchable generators as well as load resources. Providing appropriate incentives for dispatchable generation through a "firming" ancillary service and appropriate ORDC pricing should be sufficient to address these reliability needs, along with the existing ancillary service suite.

Respectfully submitted,

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Endnotes

i Even before the ORDC, additional revenues beyond the marginal energy offer were earned through administrative scarcity pricing, ancillary service revenues, and bilateral contracting, such that the “missing money” claim was not entirely founded. But that is an argument for another time.

ii The Reliability Deployment Price Adder (RDPA) and certain changes to ERCOT’s Physical Responsive Capability (PRC) calculation during EEA conditions typically cause prices to be at VOLL even earlier than 2000 MW of PRC, but this “MCL” assumption has the effect of shifting the entire ORDC curve to the right and adding value at every reserve level.

iii *See* Project No. 48551, *Review of Summer 2018 ERCOT Market Performance*, Chairman Walker Memo at 2 (Jan. 17, 2019).

iv *See* Project No. 49852, *Review of Summery 2019 Market Performance*, Independent Market Monitor (IMM) Review of Summer 2019 (Oct. 7, 2019).

v *Id.* at 15-17 and 20.

vi *Compare* ERCOT Dec. 2018 CDR at 14 (Operational Capacity Total (Nuclear, Coal, Gas, and Biomass) = 65,323.3 MW) *to* ERCOT Dec. 2020 CDR at 14 (Operational Capacity Total (Nuclear, Coal, Gas, and Biomass) = 63,622 MW)

vii *Compare* ERCOT Dec. 2018 CDR at 17 (Operational Wind Capacity Total (All Counties) = 21,535.4 MW) and 18 (Operational Capacity Total (Solar) = 1,485.4) *to* Dec. 2020 CDR at 16 (Operational Capacity Total (Wind) = 25,107.3 MW) and 17 (Operational Capacity Total (Solar) = 3835.9 MW).

viii Compare, ERCOT Capacity Demand and Reserves (CDR) Reports from May 2018 and December 2020.

ix *Compare* ERCOT May 2013 CDR at 10-15 (Operational Units Total *less* Hydro, Solar, and Storage = 64,362.30 MW) *to* ERCOT December 2020 CDR at 14 (Operational Capacity Total (Nuclear, Coal, Gas, and Biomass) = 63,622 MW).

x *Compare* ERCOT May 2013 CDR at 15 (Operational Units (Solar) Total = 73.8 MW) and 17 (10,570 MW Total Wind) *to* ERCOT Dec. 2020 CDR at 17 (Operational Capacity Total (Solar) = 3835.9 MW) and 16 (Operational Capacity Total (Wind) = 25.107.3 MW).

xi *See id.* at 7-9.

xii *Id.*

xiii *See* Project No. 40268, *PUC Rulemaking to Amend PUC Subst. R. 25.505, Relating to Resource Adequacy in the ERCOT Power Region*, TIEC Initial Comments (Jun. 15, 2012).

xiv *“Estimating the Value of Lost Load,”* Briefing paper prepared for the Electric Reliability Council of Texas, Inc. by London Economics International LLC (Jun. 17, 2013) (available at: http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf).

xv *Id.* at 1, 6.