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

COMMENTS OF The Regulatory Assistance Project

COMES NOW The Regulatory Assistance Project and files these Recommendations for improvements to the ERCOT wholesale market design, as requested by the Commission.

Introduction

The Regulatory Assistance Project (RAP) is a nonprofit group of energy and air quality experts based in the US, Europe, India and China. We bring a regulator's perspective to our work with regulators and policymakers on matters pertaining to a reliable, affordable transition to a sustainable energy system.

Executive Summary

As requested by the Commission, we have provided an Executive Summary of our Recommendations in a one-page Appendix to our submission and will not repeat them here. Our Recommendations build upon the relevant Comments in our August 26th submission.

Discussion

At 6pm on Sunday the 14th of February ERCOT was serving 70GW of demand with 72GW of available generation, 5GW above their extreme winter load scenario, with no load shedding. By 8am on Monday the 15th ERCOT was shedding 17GW of load against an estimated demand of 75GW. In the intervening 14 hours, the Texas grid lost 20GW of generating capacity, 17GW of which was "dispatchable" gas, coal, and nuclear generation. These stark facts stand against any

suggestion that the cause of the February crisis was a lack of investment in what should have been reliable generating capacity. As Joshua Rhodes, a co-chair of the PUCT-commissioned forensic analysis by UT Austin, observed in the September 5th *Dallas Morning News* regarding the widespread generation failures, "Frankly, we don't really plan to fail that badly, and honestly we shouldn't have to. No system is designed to operate reliably under that much failure." In considering changes to a market design that delivered what should have been sufficient dispatchable resources to weather a 30-year storm with a modicum of system disruption, the fix is not to saddle Texas ratepayers with mandates to pay for yet more of the same. The challenge is to ensure that the generating capacity Texas consumers are already paying for, and will pay for, especially dispatchable capacity, is up to the job.

With these as the salient facts of the context in which ERCOT's wholesale power market design is being examined, we offer the following Recommendations for the Commission's consideration. They are designed against the objective of addressing aspects of the market design that contributed to, or failed to avert the February crisis, plus some additional relevant improvements, without undermining those aspects of Texas's unique market design that have delivered as expected for Texas businesses and consumers.

Resource Adequacy

The relevant resource adequacy challenge posed by the February energy crisis is not whether there was an adequate amount of generating capacity, but whether the capacity on which the system relies is as reliable under the range of expected operating conditions as one should reasonably expect. While the resource portfolio has been very reliable under extreme summer

conditions, easily meeting or exceeding industry standards, the winters of 2011 and 2021 have demonstrated that it is vulnerable to extreme winter conditions to an unacceptable extent.

The financial incentives available under the existing market design should have been sufficient to drive more resource owners to invest in the capability to continue operating in sub-freezing conditions. Clearly far too many did not do so. The vulnerability derives from two broad categories – fuel supply chain issues and plant mechanical issues – and multiple different actions can be taken to address each category of vulnerabilities. Attempts to solve the problem through various forms of mandated reserve margins require assignment of different values of "firmness" to individual resources based on which combination of measures they choose to adopt, as well as to different categories of resources. As has been amply demonstrated in market regions with forward capacity markets, doing this properly is fraught with administrative complexity and imprecision, fertile ground for heated and interminable battles among market stakeholders. The more straightforward approach is the one considered in the wake of the 2011 event, which is to adopt mandatory standards for operability under severe winter conditions, coupled with audit and testing procedures and sufficiently onerous consequences for failure to perform, particularly during EEA2 and EEA3 events, and to allow resource owners to determine how best to respond.

There are two possible levels of mandate to be considered, based on how the costs of compliance would be recovered. The first and most urgent level is an operability standard that is determined to be sufficient to ensure compliance with an economic resource adequacy standard. (In-depth analyses of economically optimal standards for adequacy, in place of the baseless historical "1-event-in-10-years" rule of thumb, include those conducted for ERCOT by Astrapé Consulting in

January 2021 and by Brattle Group in June 2012.) As such, it can be expected that the cost will be recovered in the market, just as it has been expected that the market would support investment in an adequate amount of firm capacity.

The second and discretionary level of mandate would be a standard of resilience, perhaps extending to investing in decentralized measures such as local islanding capabilities, that goes beyond what an efficient market would deliver, one that would provide additional resilience under "high impact, low probability" events such as Storm Uri. Such investments, if they are deemed to be worthwhile, would be driven by social risk aversion that is not materially reflected in the day-to-day value consumers place on reliability. As such their costs should be socialized out of the market, perhaps through a levy collected from all LSEs and wholesale customers.

This ability to segregate "market" from "social" winterization mandates contrasts with mandated reserve margin approaches, where mandates have led inexorably to market cost recovery for investments that go beyond what is in the day-to-day interests of consumers and in so doing undermine the market's effectiveness in serving consumers reliably and at a reasonable cost.

If it is determined, nonetheless, that an enhanced level of confidence is needed in investors' ability to recover the costs of winterization mandates, we would refer to the concept exemplified by the Australian market's Retailer Reliability Obligation ("RRO") that we touched upon in our August 26th Comments, designed to act strictly as a backstop to undergird existing market incentives. Under this approach an obligation is placed on LSEs to demonstrate on an annual

basis that they have sufficient contractual commitments (financial or physical) to meet their expected supply obligations for the coming year, plus an economic margin.

Using the RRO as an example, ERCOT would annually assess the levels of resource commitment three, two and one years out. A resource gap at any of these three horizons would trigger escalating actions by ERCOT, from a warning to LSEs if a gap in cover is identified three years out, to the option to contract directly for resources and assign the related costs and terms to offending LSEs if a gap is identified one year out. If designed well, this threat of having contracts put to them, combined with the existing incentives in the ERCOT market design, should be sufficient to ensure that ERCOT's put option is rarely if ever exercised.

Even such a limited foray into mandatory reserve margins involves the potential for adverse consequences that must be mitigated in its design and implementation. It still relies on the assignment of "firm" capacity value to different resources, fertile ground for bitter disputes among stakeholders, though the use of solution-neutral winterization standards can truncate the complexity to some extent. And there is always a risk, as seen in regions that have adopted mandatory reserve margins, of "margin creep" leading to costly over-procurement and the crowding out of lower cost non-traditional alternatives, especially if an uneconomic mandate such as the "1-in-10" rule of thumb is adopted. Reliance on "capacity value" also risks inadequate differentiation of "firm capacity" resource value based on its operational flexibility.

Additional concerns with this approach are specific to the Texas market. Most important is the potential for such a mechanism to create the opportunity for market power abuse given the

degree of concentration that has occurred in recent years in the competitive retail market. To address this, one option would be to (a) require that all transactions between LSEs and affiliated resource owners be registered on a confidential basis with the Commission, and (b) limit the allowed share of LSE forward transactions with affiliated resources to a level that would ensure adequate market liquidity for all market participants. It is also worth noting that LSEs are the market actors with the best opportunity and the best incentive to optimize the use of flexible demand, and it is important to ensure they can do so. This could mean applying lower penalties to the demand response component of an LSE's portfolio for incidents of underperformance (up to some annual limit), in recognition of the fact that dispatchable demand response has proved in other regions to be highly reliable in aggregate while being more variable at an individual resource level than is the case with dispatchable generation. Doing so will increase the ability of LSEs to tap this valuable but underutilized resource.

A final recommendation to enhance resource adequacy while lowering system costs is to establish a basis for the participation of "virtual power plants" (VPPs) – aggregations of distributed resources including but not limited to demand response, batteries and distributed generation – that would be dispatchable into both the energy and the ancillary services markets on terms and conditions comparable to those applicable to generation.

Demand Response

One of the great benefits of the Texas market model is greater visibility to the value of flexibility, including the intrinsic flexibility of many sources of demand for electricity both as a dispatchable resource and as an implicit shift in the demand curve in response to market

conditions (the growing number of electric vehicles being a prime example). Yet while much has been done to tap this resource in the industrial and large commercial sectors, it remains largely untapped in the residential and small commercial sectors. The potential in these sectors becomes most dramatically manifest precisely during summer and winter peaks, when residential HVAC loads are the dominant factor in increased electricity demand. Texas's unusual degree of reliance on inefficient resistance electric heating means that this is a year-around opportunity, not just a summer peak opportunity. While some of our resource adequacy and ancillary services Recommendations refer to the role for demand response, the following Recommendations are targeted specifically at increasing the pool of cost-effective demand response opportunities.

While the potential for intrinsically flexible end uses is already large, Texas has the potential to expand that significantly by coupling investments in smart and efficient upgrades of electric energy services (particularly HVAC systems and controls) with investments in significantly improving the efficiency of the residential building stock. Each has significant value, but in combination they can create a large new pool of grid-integrated buildings as intrinsically flexible loads. Efficient building envelopes served by efficient heat pump space conditioning and water heating systems can serve as thermal batteries, making it possible to pre-heat and pre-cool buildings and shift the associated electricity consumption to periods of ample energy supply without adversely impacting consumers' comfort levels. An added benefit is that consumers become more resilient to power supply disruptions whether from severe winter storms or, as is much more often the case in Texas, tropical storms, allowing residential buildings to remain habitable for several days rather than just a few hours as is too often the case today.

Another area for potential improvement is in the removal of barriers to the development of demand response potential as an energy market resource. At least two types of barriers to participation warrant investigation: telemetry requirements and compensation. Currently the only significant possible source for dispatchable residential and small commercial loads is LSEs, yet the quantity of LSE-managed demand response remains surprisingly low relative to the participation that has been achieved in many other markets. New entrants in the LSE sector tend to be especially motivated to exploit this opportunity, yet the telemetry and measurement-and-verification requirements imposed by ERCOT appear to be overly restrictive. The Commission should investigate existing requirements that may unfairly burden demand response that could otherwise constitute a resource comparable with dispatchable generation.

The second barrier worth targeting is in the effective prohibition against entry by 3rd party demand response providers. The work done several years ago to develop a methodology for compensating such providers was unfortunately abandoned. A few 3rd party providers have forged ahead by becoming LSEs; however, the potential is certainly much greater. This effort should be revived with a focus on two possible solutions. The original effort focused on the "LMP minus g" approach, where the generation portion of the retail price avoided by the affected consumers ("g") is deducted from the price they or their service provider receive in the nodal market. That approach is problematic in some markets but is a uniquely feasible in the ERCOT market. The challenge the first time around was in setting an appropriate value for g, yet this seems an eminently solvable problem if, as with the setting of firm capacity values for generation, the perfect is not allowed to be the enemy of the good. A survey of the generation components of the basic fixed price offerings of various LSEs suggests little variance among

them within load zones, unsurprising since they are most likely based on the same averaging of real-time settlement period prices with an added risk premium. Updating g on a regular basis to reflect an average of these fixed price generation charges would likely reflect closely the actual savings realized by consumers on fixed price offerings. If this is deemed to be still too difficult, the Commission should instead consider adopting a variation on the "net benefits" test adopted by FERC in its Order 745, a reasonable compromise that encourages demand response while ensuring that it does not exceed the volume beyond which the aggregate cost of procuring it is greater than the aggregate benefit (in lower clearing prices) accruing to all Texas consumers.

Finally, moving loads above a size threshold from zonal pricing to nodal pricing would sharpen the incentives for controllable loads and improve the contribution of demand response.[1]

Ancillary Services

Ancillary services, of whatever sensibly conceivable nature, would have been ineffective in preventing the February crisis (as observed in the quote from Joshua Rhodes cited above). Nonetheless, opportunities exist to improve their effectiveness in ensuring system reliability and reducing their cost, including by enabling wider participation by demand-side resources.

The most immediate opportunity is to increase the size of the Emergency Response Service (ERS) to 3GW, principally by increasing the amount of demand response participation. In addition, the Commission should investigate the potential for an even larger ERS.

[1] See September 9th, 2021 ERCOT submission responding to the PUCT's request for comment on Demand Response

In line with industry best practice, the Non-Spinning Reserve Service should be sub-divided into two distinct services. The first would be an interim reserve (like the secondary reserve employed in many other organized markets) that would be able to ramp up within 30 minutes and sustain output for on the order of 3 to 4 hours, which would cover most events. The second would be a longer-duration reserve (like the tertiary reserve employed in many other organized markets) that can be available within that same 3- to 4-hour time frame if needed to replace and restore the interim reserve. This would bring into Non-Spin service those generators that cannot ramp up in 30 minutes but can do so over the longer time frame, and it would open the market to the valuable reserve service that many batteries and potential demand response providers could offer but are currently prohibited from doing so by the undifferentiated duration requirements.

A third ancillary service opportunity worth exploring is a day-ahead auction of energy call options on resources that do not clear in the day-ahead energy market, co-optimized with energy and other reserves. This would resemble a recent ISO New England proposal to address fuel supply vulnerabilities they have experienced, and foresee worsening, during extreme winter weather events. The details of such a service suited to the needs of the Texas market would need to be developed; however, there may be benefits in adding such an opportunity for fuel-dependent resources uncertain about their chances of being dispatched the next day to bid to be reimbursed for their up-front costs of making the necessary firm fuel supply arrangements. The quantity auctioned would be adjusted each day depending on anticipated system conditions.

Timelines have been delayed for implementation of two important improvements to ancillary services – ERCOT Contingency Reserve Service (ECRS) and Real-Time Co-optimization (RTC)

of energy and reserves. These initiatives should not only be restored to their original timelines but accelerated to the extent possible. ECRS will free up increasingly valuable fast-responding reserves by, among other things, expanding the role demand response can play, ensuring reliability at a lower overall cost. RTC will also free up valuable reserves and will give many resources, especially intermittent generators, greater ability to participate in the Day-Ahead Market, thereby increasing ERCOT's level of visibility to and confidence in the next-day resource deployment schedule, improving market efficiency and lowering overall system costs.

Conclusion

These Recommendations are provided in the spirit of addressing wholesale market design issues that contributed to or that failed to avert the February energy crisis, while mitigating or avoiding interventions having little or nothing to do with that crisis but that would compromise what is best and most successful about Texas's unique wholesale market. The Regulatory Assistance Project appreciates the opportunity to provide these Recommendations and looks forward to working with the Commission and other interested parties to pursue these Recommendations.

Respectfully submitted,

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Appendix

Executive Summary of Recommendations from the Regulatory Assistance Project.

1) Resource adequacy
   a) Adopt solution-neutral, mandatory winterization standards, with an enforcement regime, as needed to ensure enough generation can be expected to remain online in extreme winter conditions to meet an economically optimal resource adequacy standard
   b) If it is deemed necessary to bolster resource owners' confidence in their ability to recover the added costs of winterization mandates in the market, consider a reliability obligation on LSEs, taking care to address the several key risks in doing so
   c) If additional resilience measures based on "high impact low probability" events are considered beyond what the market would be expected to pay for, the associated costs should be socialized across all LSEs and wholesale customers
   d) Establish a basis for participation of "virtual power plants" (aggregations of distributed DR, generation and energy storage resources) in energy and ancillary services markets on an equitable basis with other grid resources
2) Demand response
   a) Open a proceeding on the removal of barriers to dispatchable demand response (e.g., Load Resources in SCED from both LSE QSEs and DR QSEs), such as needlessly burdensome telemetry requirements and unfair or non-existent compensation
   b) Increase the potential for demand flexibility, both as a dispatchable resource and as an embedded response, turning buildings into thermal batteries by ramping up investment in smart, cost-effective efficiency measures for residential building systems and envelopes
   c) Switch controllable loads above a certain size threshold from zonal to nodal pricing
3) Ancillary services
   a) Increase Emergency Response Service capacity to at least 3GW and explore potential for more, especially from untapped flexible demand
   b) In line with industry best practice, divide Non-Spin into interim reserves capable of 3-4 hours of operation, and longer-duration replacement reserves that can restore the interim reserves, to access untapped value from demand response and batteries
   c) Accelerate implementation of ERCOT Contingency Response Service and Real-Time Co-optimization, to increase opportunities for demand response, free up valuable reserves, and lower barriers to renewables' participation in the Day-Ahead Market
   d) Consider auctions for day-ahead call options for energy from resources that do not receive energy awards in the DAM, co-optimized with energy and other reserve products