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PROJECT NO. 52373

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

VISTRA CORP. EXECUTIVE SUMMARY

- Residential demand response broadly fits into three categories: voluntary, behavioral, and deployable/direct load control. Responsiveness and costs increase in that same respective order, but reliability is less definite due to residential demand response's myriad uncertainties, including weather risk.

- Residential demand response is likely maximized by not treating it as a "reliable and responsive" tool – it still has value, but in the ERCOT market, that value primarily comes from emergency response service (ERS) and transmission and distribution utility (TDU) load control programs.

- If the Commission wants to incentivize more residential demand response, the Commission should consider directing TDUs to reallocate some of their existing program dollars authorized under Public Utility Regulatory Act (PURA) § 39.905 towards retail electric provider (REP)-administered demand response programs.

- Capacity markets in other jurisdictions have been used to more formally incorporate demand response into the market. In ERCOT, where no capacity market exists, it is important to correct for any negative impacts on price formation created by residential demand response deployment, through the Reliability Deployment Price Adder and Operating Reserve Demand Curve.

- The Commission can improve non-residential demand response by prohibiting critical loads and generation resource support loads from participating in ERS, as well as prohibiting or penalizing early ERS deployments, so that ERCOT can count on its contracted ERS load reductions when it actually deploys ERS.

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

COMMENTS OF VISTRA CORP. ON
COMMISSION STAFF'S REQUEST FOR COMMENT

TO THE PUBLIC UTILITY COMMISSION OF TEXAS:

Vistra Corp. (Vistra) files the following comments in response to the Public Utility Commission of Texas (Commission) Staff's September 2, 2021 Request for Comments.[1] These comments are timely filed.[2] As requested, the executive summary is included in a separate attachment above.

I. RESPONSE TO STAFF QUESTIONS

QUESTION 1: Describe existing and potential mechanisms for residential demand response in the ERCOT market. (a) Are consumers being compensated (in cash, credit, rebates, etc.) for their demand response efforts in any existing programs today, and if not, what kind of program would establish the most reliable and responsive residential demand response? (b) Do existing market mechanisms (e.g., financial cost of procuring real time energy in periods of scarcity) provide adequate incentives for residential load serving entities to establish demand response programs? If not, what changes should the Commission consider?

Existing mechanisms fall mostly into the following categories: voluntary (e.g., conservation requests), behavioral incentive (e.g., reduction payments or time-of-use (TOU) pricing), and deployable/direct load control (e.g., thermostat cycling). Compensation structures vary with each of these mechanisms. Behavioral incentives are often bill credits calculated against an assumed baseline of usage or opportunities to reduce the overall electric bill through load shifting. Direct load control may be incentivized by a discount or rebate on a load control device (like a smart thermostat), a rate incentive, bill credits, or some combination thereof. As a general observation, residential demand response, while a valuable tool for the grid, is not a naturally "reliable and responsive" tool – and is likely maximized by not treating it as such.

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[1] Request for Comment (September 2, 2021).

[2] *Id.* (setting deadline for comments on September 9, 2021).

The least costly form of residential demand response (voluntary) is naturally the least reliable, since it depends on capturing public attention and spurring a meaningful percentage of households to take action, but it can also have the biggest impact. Vistra's subsidiary REPs have observed that voluntary demand response is largest when there is public awareness of potential generation shortages. For years, however, the Commission and ERCOT have annually trained REPs to not use language that might indicate resource adequacy concerns or the need for conservation unless and until ERCOT issues a conservation notice. This approach is necessary, as it protects the conservation message for times that ERCOT needs to use that reliability tool, and avoids customer demand response fatigue (i.e., it becomes less reliable the more frequently it is used). Conservation messaging also requires significant coordination and advance notice, limiting its effectiveness at eliciting responsiveness quickly.

Event-based behavioral incentives struggle with economies of scale. Consider a residential air conditioner with 5 kW load. Assume it would run non-stop across the summer peak hour, consuming 5 kWh of energy. If a customer reduces their load by 20%, they will save 1 kWh against their baseline. Assuming that a REP could hedge that load for $500/MWh, the most the REP would rationally pay is $0.50/kWh ($500/MWh ÷ 1,000 kWh/1 MWh). Thus, the residential customer would earn, at most, $0.50 for the reduction. Even with multiple events across a month, the customer may only accrue a few dollars of credits for their efforts, driving dissatisfaction, fatigue, and increased call center costs. And similar to voluntary demand response, it requires sufficient advance notice and effective messaging to translate impressions into action. While there are some residential customers that may be well-suited for such programs, Vistra's subsidiary REPs have not observed those characteristics to be suitable generally for large numbers of residential customers.

Direct load control is the most responsive of the residential demand response suite, since it is specifically deployed and recalled. That deployment signal can be delayed for several minutes, as the decision to initiate a load cycling event must be processed by the vendor and sent out to the various enrolled devices across the state. There are limits to the economics of direct load control, as well, though. Customer opt-outs, internet connectivity, and the random draw of which loads are running at a given point in time, and how those loads are cycled can mean that for every 10 residential customers, only ~1-2 kW in sustained demand response capability is gained (it varies with the weather). While this kind of demand response is much more responsive, it has reliability headwinds associated with weather variability and customer opt-outs/overrides. And it is significantly more costly to support due to hardware, installation, software vendor, and call center support costs. Scarcity pricing has historically been too infrequent to provide a consistent stream of incentives that can support large-scale adoption of direct load control, so most of these programs are either supported by TDU-administered programs under 16 Tex. Admin. Code (TAC) § 25.181 or by ERCOT's Weather-Sensitive Emergency Response Service (ERS) contracts.

These different mechanisms do an adequate job of incentivizing residential demand response today. Residential customers value the choice to respond to conservation calls or participate in behavioral or direct load control programs at different levels, and the Commission should not pursue policies with a goal of getting every residential customer to participate, as PURA § 39.001(a) dictates that "customer choices and the normal forces of competition" must be the driver of electric services and their prices. According to ERCOT's latest annual demand response survey, approximately 650,000 residential customers participated in behavioral incentives (TOU or "peak rebate"), and approximately 215,000 residential customers participated in direct load control programs.[3] However, if the Commission wants to incentivize more residential demand response, the Commission should consider directing TDUs to reallocate some of their existing program dollars authorized under PURA § 39.905 towards REP-administered demand response programs. There may be emerging opportunities for REPs to create products that leverage residential back-up generation as well.

QUESTION 2: What market design elements are required to ensure reliability of residential demand response programs? (a) What command/control and reporting mechanisms need to be in place to ensure residential demand response is committed for the purpose of a current operating plan (COP)? (b) Typically, how many days in advance can residential demand response commit to being available?

As noted above, residential demand response is not well suited for reliability and responsiveness characteristics, and the telemetry requirements that would be necessary to support real-time market participation through ERCOT's Security Constrained Economic Dispatch

[3] Totals include both NOIEs and competitive ESIIDs. *See* "Retail Demand Response Analysis for 2020". February 4, 2021 RMS Meeting: http://www.ercot.com/content/wcm/key_documents_lists/214087/15._RMS_2020_4CP__Retail_DR_Analysis_Raish.v3.pptx

(SCED) process are cost prohibitive. The Commission should therefore not be preoccupied with command/control and reporting mechanisms to commit residential demand response or reflect its availability in a COP. Rather, the best use case to continue to target deployable demand response would be to reallocate some of the existing TDU program dollars authorized under PURA § 39.905 towards REP-administered demand response programs. These programs have seasonal "commitment" to be available and are tested as a requirement for participation.

QUESTION 3: How should utilities' existing programs, such as those designed pursuant to 16 TAC §25.181, be modified to provide additional reliability benefits? What current impediments or obstacles prevent these programs from reaching their full potential?

The biggest impediment is the lack of consistent economic incentives relative to the high cost of provision. Demand response events are infrequent and don't provide enough incentives to draw participation. The Commission could procure additional reliability benefits through deployable demand response by reallocating some of the existing TDU program dollars authorized under PURA § 39.905 towards REP-administered demand response programs. Additionally, as behind-the-meter generation and storage becomes more prevalent there may be additional opportunities for REPs to create products to leverage those capabilities.

QUESTION 4: Outside of the programs contemplated in Question 3, what business models currently exist that provide residential demand response? What impediments or obstacles in the current market design or rules prevent these types of business models from increasing demand response and reliability?

ERCOT's Weather Sensitive ERS procurements and competitive customer attraction/retention value propositions are additional value levers for residential demand response. Municipally owned utilities and electric cooperatives may use residential demand response for 4CP avoidance as well. All of these channels for residential demand response, by their nature, exist outside of the market design. Capacity markets in other jurisdictions have been used to more formally incorporate demand response into the market. In ERCOT, where no capacity market exists, it is important to correct for any negative impacts on price formation created by residential demand response deployment through the Reliability Deployment Price Adder and Operating Reserve Demand Curve.

QUESTION 5: What changes should be made to non-residential load-side products, programs, or what programs should be developed to support reliability in the future?

There are a few "low-hanging fruit" changes that the Commission could make to improve the reliability benefits of the ERS program. First, prohibit critical loads and generation resource support loads from participating in ERS. Second, prohibit or penalize early deployments, so that ERCOT can count on its contracted ERS load reductions when it actually deploys ERS. Some ERS loads had pre-deployed several days before Winter Storm Uri, such that when ERCOT did deploy ERS as it entered EEA conditions on February 15, only ~400 MW of incremental load reductions showed up relative to more than 800 MW contracted.[4,5] Third, consider prioritizing loads for ERS that are located on under-frequency relay feeders or feeders with critical loads, so that the benefit of the ERS deployment would be maintained and not subsumed if ERCOT were again required to instruct firm load shed.

More globally, the Commission should direct ERCOT to adjust the ORDC calculation to account for ERS and other reliability deployments (such as TDU-directed demand response) by decreasing the calculated reserves by deployed contracted ERS MWs. While the ERS deployment impact is accounted for in system lambda via the Reliability Deployment Price Adder, the impact on the ORDC is not captured, leading to market distortions when ERS is deployed.

II. CONCLUSION

Vistra appreciates the opportunity to provide these comments for the Commission's consideration as it works to improve the ERCOT market design. Vistra looks forward to continued participation in this effort.

Dated September 9, 2021

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4 http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx see slide 13.

5 https://mis.ercot.com/misapp/GetReports.do?reportTypeId=11465&reportTitle=ERS%20Procurement%20Results&showHTMLView=&mimicKey

Respectfully submitted,

Amanda Frazier

Amanda Frazier
State Bar No. 24032198
Senior Vice President, Regulatory Policy

1005 Congress Ave., Suite 750
Austin, TX 78701
512-349-6442 (phone)
amanda.frazier@vistracorp.com