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TEXAS
ADVANCED ENERGY
BUSINESS ALLIANCE

PROJECT NO. 52373

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

TEXAS ADVANCED ENERGY BUSINESS ALLIANCE'S RECOMMENDATIONS TO REMOVE BARRIERS TO VIRTUAL POWER PLANTS AND DISTRIBUTED ENERGY RESOURCES IN ERCOT

Texas Advanced Energy Business Alliance (TAEBA) hereby submits these recommendations to assist ERCOT and the Commission in determining actions to be taken related to removing barriers to distributed energy resources (DERs), including aggregations of DERs, also known as "Virtual Power Plants" (VPPs), as discussed in Phase 1 of the PUCT's market design memorandum and blueprint.[1] TAEBA includes local and national advanced energy companies seeking to make Texas's energy system secure, clean, reliable, and affordable. Advanced energy technologies include energy efficiency, energy storage, demand response, solar, wind, hydro, nuclear, and electric vehicles (EVs). Used together, these technologies and services will create and maintain a higher performing energy system — one that is reliable and resilient, diverse and cost effective — while also improving the availability and quality of customer facing services. TAEBA's membership also includes advanced energy buyers, representing the interests of large electricity consumers interested in increasing their purchases of advanced energy to meet clean energy and sustainability goals.

Recommendations for Actions ERCOT Can Take to Remove Barriers to DERs and VPPs:

TAEBA recommends that the Commission direct ERCOT to modify market rules to facilitate full market participation for DERs and aggregations of DERs, also called Virtual Power Plants (VPPs). Participation includes submitting portfolio-level current operating plans, exporting energy, and providing regulation service, fast frequency response, non-spinning reserves,

[1] PUCT Memorandum and Market Design Blueprint (December 6, 2021), Review of Wholesale Electric Market Design, Docket No. 52373, *available at* http://interchange.puc.texas.gov/Documents/52373_268_1172004.PDF

emergency response service, and future ancillary services including but not limited to contingency reserves.

Key requirements that ERCOT should be directed to consider in implementing this policy include:

- **Definitions for DERs and VPPs**: The industry-standard, technology-neutral definition for DER is: "any resource located on the distribution system, any subsystem thereof or behind a customer meter,"[2] and should be adopted in ERCOT. VPPs (i.e., aggregations of DERs) should be defined broadly to include any combination of one or more of these resources.
- **Sizing Requirements:** Establish a minimum size requirement of 100 kW for all DER aggregations in accordance with ERCOT's system limitations allowing capacity to be offered in 100 kW increments, and avoid limitations on individual DERs participating in an aggregation. Revisit this requirement as technology improves and the ERCOT market can accommodate smaller aggregations.
- **Locational Requirements:** DER aggregations should be allowed to be as geographically broad as technically feasible, including aggregations across multiple pricing nodes (although topological constraints may be appropriate to qualify for provision of specific ancillary services such as voltage support). ERCOT may review aggregations across zones each year to ensure that no reliability or price issues have arisen as a result of increased DER aggregation. Over the long-term, ERCOT could create more granular load zones.
- **Settlement:** Ensure settlement processes include third party aggregators for robust market participation.
- **Telemetry and Metering:** Avoid cost-prohibitive telemetry and metering requirements. Telemetry should be required on the aggregate level instead of individual sites such as

[2] P*articipation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247, at P 114 (2020).

a customer's home. Further, Qualified Scheduling Entities (QSEs) in ERCOT are responsible for communicating necessary telemetry status to ERCOT. The manner in which the QSE receives that information is between the QSE, the aggregator, and the customer and is outside ERCOT's purview. For smaller DERs, telemetry requirements should be modified based on size or removed altogether. ERCOT and the PUCT should rely on existing distribution utility metering system requirements whenever possible to avoid imposing duplicative and unnecessary requirements and costs on DERs and DER aggregators. ERCOT should work with stakeholders to review practices in other RTOs and ISOs to identify and implement best practices for DER baseline definition, impact estimation and measurement and verification.

- Eliminate Dedicated Feeder Requirement: Some market participants attempting to convert Settlement-Only Distributed Generation (SODG) assets to Distributed Generation Resources (DGRs) or to develop new DGRs in order to participate more robustly and provide more value to the market have run into barriers because NPRR 1016 disallows resources to register as a DGR if it is on a load shed circuit. As a result, utilities require that resources have a dedicated feeder straight from the substation so that there is no reason to shed it. While the limitation is ostensibly intended to preserve reliability, in reality it limits DGR participation that would enhance resilience. Given the geographically and electrically diversified portfolio of DGRs that would participate through the DGR model, this requirement is unnecessary, defeats the business model for behind the meter resources, and adds significant cost (sometimes requiring new substation construction at the cost of millions). Consideration of alternative methods of allowing uninterrupted ERCOT participation will allow for robust participation from different types of distributed generation. Opening up pathways for aggregated distributed generation to participate could also alleviate this issue. For example, DER aggregators will be able to shift their provision of ancillary services if a part of its aggregation is being curtailed. In the long term, PUCT policies encouraging utility programs to increase operational flexibility and segmentation on distribution circuits will also support a more reliable grid.

Recommendations for Actions the Commission Can Take to Facilitate Market Access to DERs:

TAEBA further recommends that the Commission prioritize the following near-term policy changes that will allow individual DERs to participate more broadly in the ERCOT market:

- Update Substantive Rules to Standardize Interconnection Processes for DERs: PUCT Substantive Rule 25.211 and 25.212 should be updated to establish streamlined, transparent, and standardized interconnection requirements across all ERCOT TDSPs. Elements of a standardized process include:
    - A Standard DGR Interconnection Agreement (e.g., insurance requirements, feeder configuration, cost transparency and detailed delineation) that can be used by every utility for every DGR and filed by the utility with ERCOT.[3]
    - A standardized engineering interconnection study process and timelines that should be applied to all TDSPs, with review not to exceed 30 days except in particularly complicated conditions.
    - Clear guidance on non-discriminatory cost recovery including collateralization and recovery of appropriate costs through TDSP rates, consistent with policies for transmission level resources, and including standardization of demand charges.
    - Consideration of cost-sharing policies for system upgrades, such as transfer trip protection
    - Updated technical requirements to conform with IEEE 1547, a standard that has been implemented across the country
    - A preapproved device list for each utility to allow for shorter interconnection times. Utility interconnection rules currently do not have processes specified for

[3] These recommendations can be implemented by changes to 16 Tex. Admin. Code §§ 25.191, .192, and .198 as detailed in Comments of Hunt Energy (August 2021), Docket No. 52373, *available at* http://interchange.puc.texas.gov/search/documents/?controlNumber=52373&itemNumber=19

one-time review even if the same technology from the same company is being interconnected across the footprint.

- **Direct Utilities to Conduct Annual Capacity Reviews:** The PUCT should direct all jurisdictional utilities to conduct yearly system analyses and make capacity information available to allow customers and DER providers to identify circuits and areas of the grid that can accommodate more DERs capable of exporting back to the grid.
- **Direct Utilities to Design Systems that Include DERs as Contingency Plans:** The PUCT should direct all jurisdictional utilities to intentionally design their systems so that DERs are available and able to be deployed to address local reliability needs. For example, DERs can support the local grid during a short outage or be rotated incrementally to keep a neighborhood or community powered during a prolonged outage.
- **Initiate a Rulemaking to Compensate DERs for Value to Distribution System:** The Commission can provide policy direction regarding the value of DERs for distribution grid services such as local feeder SAIDI and SAIFI improvements, local distribution capacity relief or investment deferral, resiliency services, and voltage and VAR support. A rulemaking should aim to establish new market-based mechanisms to compensate value delivered to the distribution system by DERs. We urge the Commission to consider a variety of options including a shared savings approach which would allow utilities to earn a rate of return when they deploy DERs for the benefit of the customers and the grid (i.e., a higher rate of return on a transformer if the deployment of a DER defers maintenance on that transformer).
- **Remove the qualifiers in the energy efficiency rule that focus demand response for summer peak load relief.**

Conclusion

TAEBA appreciates the Commission's consideration of these recommendations and stands ready to work with the Commission, Commission Staff, and stakeholders to make the changes necessary to continue Texas' leadership and innovation in energy. We share a common goal: keeping the lights on and lowering costs for customers and businesses.

Respectfully submitted,

Suzanne L. Bertin
Managing Director
Texas Advanced Energy Business Alliance
suzanne.bertin@texasadvancedenergy.org
512.739.4678

Prusha Hasan

Prusha Hasan
Policy Associate
Texas Advanced Energy Business Alliance
prusha.hasan@texasadvancedenergy.org
202.999.5410

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