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PUBLIC UTILITY COMMISSION
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PROJECT NO. 48023

RULEMAKING TO ADDRESS THE	§	
USE OF NON-TRADITIONAL	§	**PUBLIC UTILITY COMMISSION**
TECHNOLOGIES IN ELECTRIC	§	
DELIVERY SERVICE	§	**OF TEXAS**

COMMENTS OF ENTERGY TEXAS, INC.

Entergy Texas, Inc. ("ETI") provides the following comments based on the questions posed in the Rulemaking to Address the Use of Non-traditional Technologies in Electric Delivery Service. This rulemaking is a positive step in determining how best to integrate new technologies that will have potential benefits to many users of electric power in Texas. ETI asks the Commission to consider how best to incent, encourage, and capture those benefits for customers.

The electric industry is experiencing a period of transformation to incorporate new technologies and evolving customer expectations. ETI's pending deployment of advanced metering systems ("AMS") is a significant step towards incorporating advanced technology into our operations to create value through enhanced reliability, operational efficiencies, and new products and services, all while providing reliable, safe, and low-cost energy, and meeting customers' changing expectations. The next phase of this transformation is grid modernization. Grid modernization generally refers to upgrading and redesigning distribution infrastructure while also adding new technologies and intelligent devices that facilitate safe, multi-directional energy flows, automated operations, remote control, increased operational efficiency, improved quality of service, increased reliability and resiliency, and expanded options for customers.

Traditionally, ETI's distribution infrastructure was designed to reliably and safely distribute energy in only one direction – from large substations to customers. However, technological advancements and increased adoption of distributed energy resources ("DERs") will require more functionality and flexibility from distribution infrastructure than currently exists. Thus, grid modernization is a necessary fundamental change to ETI's approach to evaluating, investing in, operating, and maintaining the distribution system, while monitoring and responding to the rapid pace of technological innovations and evolving customer needs and expectations. This change involves adopting a more customer-centric strategy for designing and maintaining the distribution grid – one which seeks to minimize interruptions experienced by customers regardless of fluctuating conditions on the distribution system. Grid modernization also involves expanding the functionalities offered by the distribution grid in a manner that increases customers' choices for meeting their energy needs and providing customers with access to the benefits of technological innovation.

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ETI has two key issues which it would like to address before providing its responses to the questions posed in this rulemaking:

1) ETI is not a transmission and distribution utility ("TDU") as defined by PURA.[1] ETI is a vertically integrated utility outside of ERCOT, and as such can own generation, transmission, and distribution facilities, including traditional and non-traditional technologies. Certain questions below that pertain specifically to TDUs do not apply to ETI. In those instances, ETI has either not provided a response or provided a limited response noting the different circumstances that apply to ETI.

2) Entergy believes that a key issue in addressing many of the following questions is defining the term "non-traditional technologies." It is not possible to predict with precision what "non-traditional technologies" will emerge in the future, and today's non-traditional technologies may well become adequately known or widely adopted in the future, such that they cease to be "non-traditional." Moreover, some existing and known technologies could arguably be considered "non-traditional" in that they have not traditionally or frequently been used as transmission and distribution reliability solutions.

Question 1: Apart from energy storage, what non-traditional technologies could provide a potential cost-effective solution to reliability issues on a utility's transmission or distribution system?

Response: At this time for ETI, in addition to energy storage technologies, utility-owned and operated distributed generation (*i.e.*, interconnected to the distribution system) can be classified as a non-traditional technology with the potential to provide cost-effective solutions to meet reliability criteria on both the transmission and distribution systems, as well as provide new types of supply-side and demand-side resources to serve customer load. Widely distributed generation and storage may be aggregated and controlled centrally. This can be done in the interest of improving reliability, cost, and environment.

Question 2: Can a transmission and distribution utility (TDU) legally own a non-traditional technology device, including energy storage equipment and facilities, to support reliability on its system, without a specific exemption in

[1] PURA § 31.002(19) provides, "'Transmission and distribution utility' means a person or river authority that owns or operates for compensation in this state equipment or facilities to transmit or distribute electricity, except for facilities necessary to interconnect a generation facility with the transmission or distribution network, a facility not dedicated to public use, or a facility otherwise excluded from the definition of 'electric utility' under this section, in a qualifying power region certified under Section 39.152, but does not include a municipally owned utility or an electric cooperative." ETI operates in Midcontinent Independent System Operator, Inc. ("MISO") power region, which has not been certified under PURA§ 39.152.

the Public Utility Regulatory Act? If so, under what legal authority could a TDU own such a device?

Response: ETI is not a TDU, but rather a vertically integrated utility operating outside of ERCOT. ETI's vertically integrated operations do not present the same questions regarding the appropriate entity to own and operate batteries or non-traditional technology. ETI is the sole provider of electric service to its customers. ETI can and does own generation, transmission, and distribution facilities. Regardless of which functional category is assigned to a particular technology, ETI must retain the managerial discretion to provide or deploy any traditional or non-traditional technology available to cost-effectively and reliably maintain its electric system and to meet customers' growing needs and demands for innovative ways to manage their energy use.

Question 3: How should any energy necessary for TDU implementation of a non-traditional technology device be measured and accounted for within the ERCOT market, without using Unaccounted for Energy (UFE)?

Response: See ETI's response to Questions 2. As a vertically integrated utility in MISO, ETI has no further comment at this time but reserves its right to provide responsive comments on this question.

Question 4: In which situations and scenarios would it be appropriate for a TDU to deploy a non-traditional technology device for the purpose of supporting reliability on its transmission or distribution system?

Response: See ETI's responses to Questions 2 and 13. As a vertically integrated utility in MISO, ETI has no further comment at this time but reserves its right to provide responsive comments on this question.

Question 5: Should a Certificate of Convenience and Necessity (CCN) or other commission pre-approval process be required before the construction or procurement of utility-owned devices that use non-traditional technologies to support reliability on the transmission or distribution system? If so, what criteria would be appropriate for pre-approval of such devices and why? Should such a pre-approval process only apply for a limited time?

Response: No. There are presently no certification requirements for distribution assets and nothing about the introduction of non-traditional technologies warrants a departure from current practice. Regardless of the functional classification of a particular technology, the Commission should not enact any prescriptive rules or requirements beyond what is already in place. Under the regulatory compact, vertically-integrated electric utilities in Texas are ultimately responsible for providing safe and reliable electric service to customers at a reasonable cost. This obligation extends to maintaining the reliability of the entire electric system, which presents decision-making scenarios that are complex, fact- and asset-specific, and often, time-sensitive. Vertically-integrated utilities are in the best position to assess the specific needs of their electric system and, as the entities ultimately responsible for providing safe and reliable electric service to customers, and must retain the managerial flexibility and discretion to make investments in a timely manner determined to be most appropriate and cost-effective to maintain reliability.

In the alternative, should the Commission determine that a pre-approval process is necessary for specific technologies, the appropriateness of any such process would depend on the characteristics of the particular "non-traditional technology" and the particular scenario (reliability or otherwise) to which that technology could be applied. For instance, it would be impractical and unnecessarily costly to implement a pre-approval requirement for investments that are relatively small and fall within the ordinary bounds of managerial decision-making to serve customers' needs. It would also be impractical and poor policy to implement such a requirement if the resulting delay from the regulatory process would prevent or hinder a utility from utilizing the best possible solution, including upgrades to existing facilities. As technologies and customer needs and expectations continue to evolve at a rapid pace, utilities need to be in a position to react quickly and cost-effectively. The imposition of costly and time-consuming pre-approval requirements and litigation will have a chilling effect on the adoption and deployment of new technologies and solutions to address the needs of customers. The Commission presently has adequate means of evaluating the reasonableness of a utility's expenses and the prudence of a utility's investments through various ratemaking proceedings. In many scenarios, this after-the-fact review of utilities' actions represents the most logical, effective, and appropriate balance considering the Commission's need for oversight and the utilities' obligation to maintain system reliability and managerial discretion to do so and effectively run their businesses.

Should the Commission adopt specific pre-approval requirements, any such requirements should be limited to investments over an established size and dollar threshold, such as greater than 10 MW and a dollar threshold (to be determined). The 10 MW size limitation would be consistent with 16 T.A.C. § 25.211(c)(10) (defining distributed generation as being 10 MW or less) and 16 T.A.C. § 25.101 (exempting from certification experimental facilities that are 10 MW or less). A dollar threshold (to be determined) would support efficiency and practicality by not requiring utilities to seek, parties to litigate, and the Commission to approve certification of less expensive assets. Regardless of the asset size or cost, any pre-approval requirement should be subject to appropriate exceptions for time-sensitive reliability scenarios. In addition, the scope and duration of any new pre-approval process established by the Commission should be appropriately suited to the cost and complexity of the technology at issue, and the nature of the issue being addressed by the investment. The existing lengthy and costly CCN processes for transmission assets and large generation facilities would be ill-suited to the deployment of smaller, less expensive assets.

Question 6: **Should the commission's rules permit or require a TDU to contract with a non-utility service provider for the provision of a non-traditional technology device to support reliability on the TDU's transmission or distribution system? If so, what parameters should the commission stipulate for this arrangement?**

Response: See ETI's response to Question 2. As a vertically integrated utility in MISO, ETI has no further comment at this time but reserves its right to provide responsive comments on this question.

Question 7: **If the commission were to adopt a policy of permitting a TDU to procure a non-traditional technology device for the purposes of supporting reliability on the TDU's transmission or distribution system, what potential effects would such a policy have on ERCOT wholesale market outcomes, and especially price formation, in the ERCOT market? What potential effects might such a policy have on the competitive retail market, if any?**

Response: As a vertically integrated utility in MISO, ETI has no comment at this time but reserves its right to provide responsive comments on this question.

Question 8: **What market-based alternatives exist, if any, to address reliability issues on a TDU's transmission or distribution system?**

Response: See ETI's response to Question 2. As a vertically integrated utility in MISO, ETI has no further comment at this time but reserves its right to provide responsive comments on this question.

Question 9: **How could a vertically integrated investor-owned utility maximize the value of an energy storage device without adversely affecting wholesale market outcomes and price formation in its respective market?**

As a member of MISO, ETI is a participant in MISO's wholesale markets for capacity, energy, and ancillary services, but energy storage devices can also provide many non-market reliability services such as voltage control and management of congestion and thermal overloads that can maximize their value without participation in wholesale markets.

Regarding wholesale market participation, in compliance with FERC Order 841 ("Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators"), MISO is developing rules to support participation in MISO's wholesale markets, due to be filed at FERC by December 3, 2018. These participation requirements will include metering that will track the dispatch of storage devices for market participation or reliability needs, and provide the ability to bifurcate the performance of these functions in settlements.

Simultaneously, MISO is developing rules relating to Storage as Transmission Assets ("SATAs"), and has indicated that energy storage devices that are approved through the MISO Transmission Expansion Plan ("MTEP") planning process will be subject to dispatch by MISO to address any reliability issue that it is able to address. This utilization of these assets by MISO does not provide for predictability in the availability of these devices to participate in wholesale markets, as they are required to maintain a state of charge that will support the anticipated reliability function. Therefore, it is more likely that these devices will be Locational Marginal Price ("LMP") "takers" than LMP "setters" in MISO's wholesale markets. However, in the event that market revenue is earned, it can be credited against the Transmission Revenue Requirement, to the benefit of the same customers who are served through wholesale market participation.

While the implementation timeline of Order 841 is subject to rehearing requests, in particular relating to FERC's jurisdiction over wholesale market participation by distribution connected energy storage devices, after which, the parties can seek review in the court of appeals, FERC has already issued a policy statement confirming its prior Orders supporting the recovery of energy storage devices as transmission assets.

Outside of Order 841, there are several different, currently available methods for using energy storage devices in MISO markets. There should be a presumption that, rather than adversely affecting price formation, the opposite would be the case for such devices. That is, incorporating energy storage would lead to increased competition due to the ability of storage devices to manage their state of charge, and ultimately, lower overall costs for retail and wholesale customers.

However, such devices should be appropriately registered and metered, and receive settlement statements through the MISO market.

Question 10: What impediments exist to using non-traditional technology devices on utility transmission or distribution systems?

Response: The requirement to obtain a CCN would be an impediment to the rapid deployment of a device. As mentioned above, no new pre-approval processes should be established. In the alternative, for the bundled utilities such as ETI, the Commission should expressly exempt a storage device, distributed generation, or other technologies that are up to 10 MW or a dollar threshold (to be determined) from the requirements to obtain a CCN.

Uncertainty regarding asset classification from a FERC accounting perspective could present an impediment to the adoption of non-traditional technologies. Traditionally, small batteries have been treated as components of the system they support. For example, batteries in a control house are part of the protection system, in a data center they are part of the facility, when supporting a specific transmission or distribution device they are accounted for as part of that device. A simple rule could be: if connected to transmission the device is accounted for as transmission; if connected to distribution the device is distribution; if connected to a customer system the device is accounted for as a "service"; if connected to a generation facility it would be "generation." This rule would be consistent with how MISO intends to treat SATAs being used to address a transmission reliability need identified through the MTEP planning process.

Depending on the applicable ratemaking framework and specific cost recovery mechanism in place, a utility could be disincentivized from making certain grid modernization-type investments on its distribution system. For example, utility investments in certain distribution technology solutions could achieve increased operational efficiencies and lower costs to retail consumers but also result in immediately reduced sales and earnings. Unless the utility has a ratemaking framework and specific cost recovery mechanism in place to adequately address the economic effect of such solutions, the utility could be disincentivized from investing in the technology solution even if there were timely recovery of the direct cost of the investment itself. Regulators that have been presented with proposals from utilities to invest in new technology solutions have recognized the inherent disincentive associated with negative economic effects and have issued approval orders that address the issue recognizing that there is a need to balance the interests of all stakeholders.[2]

Question 11: Could the commission specify conditions under which a TDU could employ nontraditional technologies to support reliability? If so, what conditions would be appropriate?

Response: See ETI's responses to Questions 2 and 5.

Restricting a utility's ability to maintain reliability through the establishment of a prescriptive and potentially ill-fitted set of conditions could result in a suboptimal deployment of both traditional and non-traditional technologies, reduced reliability, and increased costs.

Question 12: If you are a utility, please provide a detailed overview of any batteries or other energy storage technologies on your transmission and distribution system in the state of Texas that are either currently operational or planned to be operational. Please explain the purpose, use, metering, and deployment of these technologies.

Response: At this time, ETI does not have any energy storage devices operational in Texas. However, ETI is currently performing analysis to further evaluate the potential future application of energy storage devices in its service territory.

ETI is also working with Electric Power Research Institute ("EPRI") to understand distribution and transmission interconnection options and potential impacts as these interconnections both allow for peak shaving and support consideration of deferral of capital investments.

Question 13: Are there any other issues that the commission should consider addressing in this project?

Answer: With regard to vertically integrated utilities such as ETI, there are several known scenarios in which potential benefits to customers can be realized through optimized planning and siting of non-traditional technologies rather than traditional "wires" solutions on both the transmission and distribution systems.

[2] See Colorado Public Utilities Commission Decision No. C17-0556 dated June 21, 2017; Proceeding No. 16A-0588E; *IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR DISTRIBUTION GRID ENHANCEMENTS, INCLUDING ADVANCED METERING AND INTEGRATED VOLT-VAR OPTIMIZATION INFRASTRUCTURE.*

One scenario where benefits may be realized, depending on the specific facts and circumstances, is in the utilization of distributed generation to offset load during peak conditions in order to defer (or in some limited instances avoid) more costly capital investment in traditional solutions like upgrades to the transmission or distribution systems or supply-side and demand-side resources. For example, the optimized deployment of energy storage devices, such as batteries, and/or distributed generation installed on a particular distribution feeder could reduce substation power transformer loading during periods of high demand, and potentially defer the costs of a upgrading a substation transformer.

Another potential scenario is through the use of microgrids featuring distributed generation and/or electric storage to reduce customer interruptions and outage durations. For example, installation opportunities may exist in areas where sole source outages have long restoration durations.

Other potential scenarios of implementing energy storage to support reliability include system black-start plan integration as well as voltage support to offset potential variations in solar photovoltaic ("PV") and wind generation to improve power quality and system stability.

Given that ETI is a member of MISO, MISO's FERC 841 compliance plan, combined with their current work on SATA will have a significant impact on the opportunities available for storage participation in both MISO's markets and as transmission assets, as described more fully in response to Question #9.

MISO is also currently assessing potential changes to its business practice manuals to implement energy storage devices as non-traditional transmission assets in the MISO MTEP reliability planning process. Such devices would ultimately be classified as transmission assets if they are selected as the preferred solution to an identified transmission issue.

MISO is considering crediting the appropriate Transmission Pricing Zone's Attachment O revenues with revenues/charges for energy storage transmission solutions where such revenues or charges from the MISO market are accrued due to dispatch by MISO for reliability purposes. For reference, MISO's Attachment O revenues are similar in principle, with some differences, to ERCOT's Transmission Cost of Service ("TCOS") allocation of charges according to a load serving entity's use of the transmission system (based on load ratio share within a transmission pricing zone).

ETI would appreciate the Commission's participation and support in the MISO stakeholder processes that address these issues in an effort to ensure ETI is the best position to bring the benefits of non-traditional technologies to its customers.

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Respectfully Submitted,

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