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PUBLIC UTILITY COMMISSION
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PROJECT NO. 48023

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

COMMENTS OF PUBLIC CITIZEN

Public Citizen is a nonprofit consumer advocacy organization that champions the public interest. Our Texas office represents the interests of energy consumers by advocating affordable, reliable, and sustainable energy policy and infrastructure choices.

Public Citizen appreciates the opportunity to comment on these important topics and commends the Commission for opening this project to develop a thoughtful, holistic approach to advanced technology applications in transmission and distribution system planning and operations. Many such technologies offer smart, cost-effective, reliable alternatives to traditional "poles and wires" investments, an approach that can provide ratepayer benefits by minimizing the costs of maintaining reliability and maximizing efficient use of existing infrastructure. Public Citizen therefore encourages the Commission to think broadly in this proceeding about enabling transmission and distribution utilities (TDUs) to utilize "non-wires alternatives" when and where these benefits are available.

Public Citizen does support TDU ownership of non-traditional technologies as a means to modernize the grid and enhance reliability at lower costs to ratepayers. But we believe the most

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efficient deployment of such technologies comes with market participant ownership and TDU access. This will minimize risk to ratepayers and disruption of competitive wholesale and retail market mechanics. TDUs should contract for reliability services whenever possible before considering owning and operating such technologies themselves. In this model, the TDU assumes a greater role as the coordinator of device operations on its system, compared to its traditional role as a sole provider of reliability functions. This approach keeps with the fundamental principles of the ERCOT market design that the Commission should look to competitive solutions before adopting regulatory ones[1] and that the core mission of TDUs is to ensure non-discriminatory open access to a reliable delivery system for market participants to bring energy products and services to consumers.

RESPONSES TO STAFF QUESTIONS

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?

Apart from energy storage, TDUs can achieve cost-effective reliability solutions through utilization of controllable load resources (CLRs), demand response (DR), and distributed energy resource management systems (DERMS). Each of these non-traditional technologies can be utilized by TDUs to defer investment in traditional transmission or distribution equipment, especially for solutions required to meet peak demand scenarios during only a handful of hours each year. Similar to energy storage, each of these non-traditional technologies (DERMS, CLRs, and DR) may also be utilized by wholesale or retail electricity market participants or by retail electricity consumers and, therefore, require careful thought by the Commission to determine how best to capture the cost-effective reliability benefits they offer to TDU operations while

[1] *See* PURA 39.001(d).

maintaining appropriate divisions between regulated delivery service and competitive markets for energy and ancillary services.

As the costs of photovoltaic (PV) solar and battery-based energy storage resources (ESRs) falls and as the "internet of things" (IOT) adds millions of devices, the future of the grid is decentralization and increasing elasticity and responsiveness on the demand side. Enabling TDUs to capture the system benefits available through coordination of DR, CLRs, and DERMs could yield significant total system savings and reliability benefits. Public Citizen encourages the Commission to seek and find the most appropriate path to the benefits offered by such technologies.

Some TDUs in the ERCOT region already use these non-traditional technology solutions. For example, Austin Energy's Power Partner Thermostat program allows the utility to adjust participating thermostats by a few degrees during high demand periods. By coordinating a portion of the air conditioning loads across its system, the utility shaves peak energy demand and avoids potential reliability problems without inconveniencing participating consumers. It is a win-win approach that works well within a vertically-integrated non-opt-in entity (NOIE) service territory without retail electricity choice. But it raises legitimate concerns of market impacts within the competitive choice areas of investor-owned TDUs where customers procure energy services from competitors in an open market.

To some degree, the question of TDU engagement with DERMs, CLRs, and DR overlaps a long-running effort within the ERCOT stakeholder process to remove barriers to wholesale market participation by the owners of such technologies. In some respects, the kinds of benefits available to the system through market participation by advanced devices are quite similar to the reliability benefits that TDUs could realize by deploying such technologies. This suggests that

Commission rules should enable and encourage "value stacking," *i.e.*, allowing competitive market resources to access multiple payment streams for the provision of different kinds of services through both wholesale market participation and TDU contracts for services.

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

Because energy storage technologies are most explicitly addressed in current law, Public Citizen will first focus on TDU ownership of ESRs. We favor ownership of ESRs by market participants over TDUs, which is a solution we see as more efficacious and less likely to lead to unintended market consequences. But it seems clear as a matter of law that TDUs can own energy storage facilities. Although a number of stakeholders have argued in prior proceedings that PURA §39.152(a) specifies that ESRs are only to be owned and operated by registered power generation companies (PGCs), Public Citizen disagrees, noting that PURA §35.151 clearly states, "This subchapter applies to electric energy storage equipment or facilities that are intended to provide energy or ancillary services at wholesale ...". PURA Chapter 35, Subchapter E does not apply to all electric energy storage equipment or facilities, only those owned by PGCs for participation in the wholesale market. When the Texas Legislature adopted that language in 2011,[2] it was not addressing all applications of energy storage devices, only one particular application. In fact, the Legislature explicitly stated in PURA §35.152(c) that, "this section does not affect a determination made by the commission in a final order issued before December 31, 2010." Contrary to popular understanding, PURA §35.152(c) did not "grandfather" the Presidio facility from the provisions of subsection (a). Rather, subsection (c)

[2] Senate Bill 943, Act of the 82nd Texas Legislature.

makes plain that subsection (a), *i.e.*, the ability of a PGC to register and operate an ESR in the competitive wholesale market, has nothing to do with whether or not the Commission determined that an ESR in another application should be considered an asset appropriately owned and operated by a TDU as the Commission did in the Presidio case.[3] The Legislature was addressing a narrow issue that arose when a PGC and its interconnecting transmission service provider (TSP) failed to reach agreement on whether a proposed battery qualified to be interconnected as a generation resource.[4] The ability of the Commission to determine that an ESR may properly be categorized as a transmission or distribution facility was expressly not impacted by the legislative determination that PGCs should be the owners and operator of ESRs engaged in wholesale market competition.

Although Public Citizen believes it is important to preserve the Commission's flexibility to approve TDU ownership of ESRs in those cases where such ownership makes the most sense for ratepayers, we note that TDU ESR ownership raises important market design concerns and potential adverse impacts on the competitive marketplace. Therefore, we rank TDU ownership of ESRs as the least desirable outcome of any particular proposed TDU ESR solution. Most of the market design challenges arising from TDU ESR deployment are negated if the TDU deployment model is through a contract with a PGC for third-party reliability services. The reliability service provider (RSP) model is not without its own policy questions. For example, would the TDU need to purchase ESR charging energy or could the TDU simply pay the PGC a

[3] P.U.C. Docket No. 35994, *Application of Electric Transmission Texas, LLC for Regulatory Approvals Related to Installation of a Sodium Sulfur Battery at Presidio, Texas*, "Order," April 6, 2009, Conclusion of Law No. 5, p. 12. "ETT's NaS battery meets all the requirements for transmission service as set forth in P.U.C. Subst. R. 25.192(c)(1)(D)." See also Finding of Fact No. 51, p. 11, "The proposed uses of the battery by ETT are appropriate for a transmission utility because they provide benefits associated with transmission service operations, including voltage control, reactive power, and enhanced reliability."
[4] Public Utility Commission of Texas, *Docket No. 39236 Petition of CenterPoint Energy Houston Electric, LLC and AES Deepwater, LLC for Declaratory Order*. See Original Petition, pp. 3-5. The petition was withdrawn three days after Gov. Rick Perry signed SB 943.

service fee that covers the cost of providing the reliability service, therefore, never taking title to power? If the TDU must purchase the charging energy, would such a purchase comport with PURA §39.105(a) which allows a TDU to buy electricity, "to serve its own needs," given that the electricity is a necessary component of the reliability function, which is, after all, the core mission of the TDU? Similar questions arise regarding the flow of energy from the ESR in the performance of the reliability function. Despite these and other policy questions arising from the third-party RSP model for TDU deployment of ESRs, in many respects the model seems to fit well within existing market structures – PGC ownership of ESRs, processes of ESR interconnection and access to the wholesale market, ERCOT settlement of wholesale storage load (WSL), etc. are all well-established market rules and systems. For this reason, in particular, the Commission should further investigate the TDU-RSP model for ESR deployments for reliability purposes.

3. How should 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)?

Public Citizen generally agrees with the broad critique of UFE as a settlement or accounting mechanism for TDU-owned ESRs but has not yet identified an appropriate settlement methodology to recommend for energy in and out of a TDU-owned alternative technology device when such energy is injected or withdrawn at the direction/discretion of the TDU. This is a fundamental market design challenge. However, settlement methodologies and mechanisms already exist for many non-traditional technologies owned and operated by PGCs, retail consumers, and competitive energy services providers. The TDU-RSP reliability services contract model seems to offer the best opportunity to preserve and leverage existing market rules and systems to settle and account for energy used, stored, or managed by such alternative technologies when performing a reliability function for a TDU, whether such RSPs are wholesale market participants or retail market participants.

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?

Harnessing modern technologies can defer expensive upgrades to wires and poles or even substitute for them altogether. Modern technologies can be applied to prevent overloading of essential equipment and can provide services during system emergencies that wires alone cannot. Alternative technologies can provide solutions where environmental, economic, aesthetic, and other factors limit the ability to install traditional technology solutions. Public Citizen strongly encourages the Commission to develop the regulatory clarity necessary to enable the application of non-traditional technologies to transmission and distribution system reliability challenges.

The proper preference for the deployment of non-traditional technology devices for the purpose of supporting reliability on a transmission or distribution system should be to first enable competitive market participants to deploy the technology through market constructs that serve the reliability need, much in the way ancillary services provide critical services in today's market. The second preference should be for a TDU to contract for a specific reliability service from a third party RSP which would be a competitive market participant. The third preference should be for TDUs to own and operate the non-traditional technology.

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?

Yes, some pre-approval standards should be developed by the Commission. Pre-approval would be especially important if the devices at issue were owned by TDUs. In order for prices to be kept as low as possible for consumers, TDUs must employ the most cost effective option from a range of possible solutions to a reliability issue. The best way to ensure this happens is transparency in the distribution planning and procurement process. If TDUs choose a particular solution without publicly considering all available options, or if they choose without any oversight, there is a risk that they will not choose the most economic option. If this choice happens outside of the public eye, then it could be difficult to assess the validity of a choice during a DCRF amendment consideration.

Public Citizen recommends that for any project above a given dollar amount (to be determined by the Commission, but below the currently stipulated CCN threshold amount) TDUs be required to issue a request for proposals (RFP)--whether it be for a transmission or distribution level project--for a reliability service contract. This RFP, and the responses received, could then be held as record by the TDU to support final decisions regarding capital expenditures. This would help TDUs to demonstrate that they are performing their fiduciary duty to both their owners and their ratepayers, by highlighting how only prudent, reasonable, and necessary solutions were implemented in the course of providing reliability in the most cost-effective way.

The Commission should adopt standards for this RFP process that further outline the threshold (by dollar amount, or class/size of assets) above which this requirement is triggered, as well as performance and reliability standards, enforcement, liability and administrative penalties, and registration. The RFP, the resulting submissions, and any documents related to the deliberative process of choosing among options should be preserved and available for public review. The TDU's process should include a requirement to issue the RFP and preserve the appropriate documents.

Importantly, the Commission should not need to evaluate these documents as part of a pre-approval process unless a protest is filed. Documentation should be created and retained that is sufficient for evaluation in a later DCRF amendment consideration, should one occur in the future.

We believe that this level of pre-approval would not overburden Commission staff and would be adequate to ensure the TDUs were making the best decisions for consumers.

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?

The Commission's rules should explicitly permit and clarify that TDUs may seek contractual solutions with non-utility service providers for the purpose of maintaining reliability, where such a contract is the more prudent, reasonable, and necessary solution, prior to proposing to own and operate non-traditional technologies. In such an arrangement, the Commission would need to carefully consider the proper chain of ownership of energy required to provide the reliability service and the methodology for market settlement of such energy. The Commission would also need to consider the proper assignment of compliance obligations and penalties associated with RSP performance (or non-performance) of the reliability service. Finally, the Commission may need to clarify the categorization of reliability service contracts as plant or property eligible for return on invested capital to provide the proper incentive for TDU utilization of the RSP contract model.[5]

Current rules may already allow for such arrangements. Where Substantive Rule §25.231(c)(2), "Invested capital; rate base", states under subparagraph (A) that components to be included in the rate base are "Original cost, less accumulated depreciation, of electric utility plant used by and useful to the electric utility in providing service." We note that it says "used and useful to," but does not say "owned by." It goes on to say:

> (i) Original cost shall be the actual money cost, or the actual money value of any consideration paid other than money, of the property at the time it shall have been dedicated to public use, whether by the electric utility which is the present owner or by a predecessor.

Here we note that the term "property" may refer to both tangible and intangible assets, as made clear by the Public Utility Regulatory Act §11.003(10), where "Facilities" is defined as "all of the plant and equipment of a public utility, and includes the tangible and intangible property, without limitation, owned, operated, leased, licensed, used, controlled, or supplied for, by, or in connection with the business of the public utility."

Finally, we will note that PURA goes on to state in §31.002(19) that a "Transmission and distribution utility" is a "person or river authority that owns or operates for compensation in this state equipment or facilities to transmit or distribute electricity[.]" This makes it clear that the TDU does not have to own the equipment in question.

From this, we conclude that current rules do allow for TDUs to enter into contracts with third-party owners of equipment, where such contracts allow the TDU to use said equipment for

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[5] See P.U.C. Subst. R. 25.231(c)(2) and 25.243(b)(3).

the purpose of maintaining reliable service for their customers, and that these contracts may be treated as intangible property and allowed to be included within the TDU's rate base.

This assessment is further supported when considering the treatment of the Distribution Cost Recovery Factor by considering the language in Substantive Rule §25.243(b)(3) that defines "Distribution invested capital" as:

> The parts of the electric utility's invested capital, as described in PURA §36.053, that are categorized as distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks properly recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 352, 353, 360 through 374, 391, and 397. Distribution invested capital includes only costs: for plant that has been placed into service; that comply with PURA, including §36.053 and §36.058; and that are prudent, reasonable, and necessary.

And here we note that the FERC Uniform System of Accounts defines 303, "Miscellaneous intangible plant," as including "the cost of patent rights, licenses, privileges, and other intangible property necessary or valuable in the conduct of utility operations." Public Citizen asserts that a capitalized contract for reliability service may reasonably be included within account 303.

So, where there may be occasions wherein a reliability service contract with a third-party owner of a non-traditional technology device would be the prudent, reasonable, and necessary solution, it seems that the TDU would be allowed to earn a rate of return on the capitalized cost associated with the contract.

That said, the Commission could consider adding clarifying language to the preceding sections of the substantive rules to stipulate the criteria by which contracts for reliability services provided by third party owners of non-traditional technologies are allowed in the cost of service rate base, or as part of distribution invested capital.

These criteria should be broad enough as to not be fully prescriptive of all legal obligations to be included in such contracts, but may--as a matter of course--require that the contracts include language that addresses liability. This, we suggest, could be aligned with the Commission's own enforcement procedures, such that penalty calculations and compliance histories may address those issues that may arise by way of a reliability service contract.

Additionally, for reliability service contracts that implicate the use of non-traditional technology devices that may inject energy into the transmission or distribution system, the Commission could stipulate that counterparties for such contracts must be duly registered as Resource Entities with the Commission, and that the devices must be appropriately registered with ERCOT.

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?

The market impacts likely vary depending upon the model of TDU "procurement." In the particular case of a TDU-owned ESR, the question of energy settlement for charging and discharging has obvious direct consequences on price formation although the magnitude of price impacts is largely unknown at present. In the case of other TDU-owned equipment, the market impacts are less clear and perhaps less significant, although it should be considered whether the mere presence of TDUs in the space inhibits robust market participation or new participant market entry. On the other hand, if the "procurement" were for third party services that the TDU coordinates to improve reliability and defer system investment, the results could be beneficial to ratepayers and empowering to retail consumers who participate in distributed energy management system portfolios. Generally speaking, Public Citizen believes reliance upon market-based approaches will deliver solutions with the least disruption to price formation and other key market mechanics while likely also delivering the most cost-effective reliability solution for ratepayers.

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

To address this question, we must acknowledge that "reliability issues" take many forms. There are many reliability needs (addressing voltage sag, power-factor correction, harmonic distortion, etc.) that are necessarily local, and which may not best be addressed in real-time by a market-wide (grid-wide) product. However, for reliability needs that can broadly be categorized as relating to transmission constraints, the existing market-based solution of incorporating those constraints into the calculation of locational marginal prices is a reasonable "alternative" to addressing those reliability needs--but only over the long term, and only if market participants decide that the price premium resulting from the constraint is enough to drive investment in a solution to that location. Meanwhile, the TDU has compliance requirements that it must maintain or face enforcement penalties. It is the lack of certainty provided to the TDU by the market that a market-based alternative will materialize as a result of LMP enticement, and the timeline required for the TDU to design and install a non-market solution, which results in TDUs feeling prudently and reasonably compelled to act.

This issue is compounded for distribution system operators, where even fewer market incentives may exist for Resource Entities considering operations of resources located on the distribution system. This is due to the challenges that smaller, distribution-interconnected resources may have, when considering registration pathways to engage the ERCOT ISO and the ERCOT markets.

The strategies required to get market participants to take actions that tend to support distribution grid reliability needs--insofar as those needs are similarly related to throughput constraints--will require continued work by ERCOT staff and market members.

Appropriate market incentives (including locational pricing) and improved visibility into the distribution planning process may allow for "market-based alternatives" to materialize, insofar as Resource Entities may, as efficient market actors, determine that it is reasonable to invest in resources at locations that are being identified via the planning process as potentially experiencing congestion--and thus higher prices.

However, this will not obviate the TDUs' need to take the prudent, risk-mitigating actions that they feel are necessary to maintain compliance and avoid enforcement actions. Binding contracts for reliability service, which address liability concerns, are one pathway that TDUs may consider to mitigate their risk.

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?

Public Citizen does not have an answer to this question at this time.

10. What impediments exist to using non-traditional technology devices on utility transmission and distribution systems?

The impediments that exist to using non-traditional technology devices depend, in part, on the ownership of these devices. As we state in our answer to Question 2, they may be owned by the TDU, or, as we state in our answer to Question 6, they may be owned by a third-party who provides operational access to them via a reliability service contract with the TDU. There are different impediments in either cases.

In the first case, where the TDU may own the non-traditional technology device, we agree with many of the concerns raised by other parties. There are legitimate concerns associated with the settlement impacts--due to uplift and price distortion--resulting from the potential Unaccounted for Energy (UFE) treatment of these devices.

In the second case, where the TDU is only using the non-traditional technology device via a reliability service contract, the impediments may be categorized broadly as a need for transparency, a need to align incentives, and a need for clarity.

Regarding the need for transparency, Public Citizen observes that distribution planning in Texas does not generally undergo the same level of oversight as is afforded to transmission planning--which includes due consideration via the ERCOT Regional Planning Group and Planning Working Group. The lack of insight into expected distribution needs hinders the ability of Reliability Service Providers to apply their analytical power and project concepts to distribution system challenges across the state. More clarity, in this case, and a standard expectation of the issuance of RFPs (as recommended in our response to Question 5) will invite more competition and market forces to drive more prudent, reasonable, and potentially innovative, reliability solutions.

Additionally, Public Citizen observes that TDUs in Texas may not be properly incented to contract for reliability services from third parties if the costs of such contracts must be passed through as expenses rather than capitalized as assets eligible for rate recovery. To this end, we recommend in our response to Question 6 that the substantive rules clarify the circumstances under which a reliability service contract may be included in the rate base.

Finally, the lack of clarity regarding how and when a TDU may utilize non-traditional technology devices via reliability service contracts is an impediment, but it is one that may be addressed by adding clarifying language to the substantive rules (as suggested in our response to Question 6), and by providing supporting documentation that stipulates the nature of RFPs for such contracts (as suggested in our response to Question 5).

For the reasons stated herein, Public Citizen believes that solving the impediments addressing reliability service contracts is the best approach to enabling the TDU utilization of advanced technologies and encourages the Commission to do so in this proceeding.

11. Could the commission specify conditions under which a TDU could employ non-traditional technologies to support reliability? If so, what conditions would be appropriate?

As we explained above in the answer to Question 2, we favor ownership of non-traditional technologies by market participants over TDUs. The condition that we would prefer—from the perspective of providing the most efficient solutions and therefore the lowest cost to consumers—is for TDUs to "employ" non-traditional technologies by contracting for reliability services from RSPs. The commission should develop a process to enable this model.

A contractual relationship between a distribution service provider (DSP) and a third-party owner raises an issue when the third-party fails to deliver on the contract in a way that affects reliability and subsequently impacts the DSP's SAIDI/SAIFI metrics. Sophisticated actors should be able to enter into contracts that account for this, potentially offloading of the DSP's liability to a third-party, but the commission might still want to consider adjusting its enforcement policies to address the third-party's role.

Although we believe that current regulations already allow for the RSP contract model as we have previously described it, the Commission could take the opportunity to clarify its rules.

The Commission could first clarify that a third-party contract is eligible to be included in the TDU's capital base for rate of return. The rules could also specify how a contract could address the enforcement liability issue, that is, what aspects of liability, if any, could be offloaded into a contract.

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.

This question does not apply to Public Citizen.

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

Yes. The Commission should also include issues related to electric vehicle (EV) charging in this project. EVs are not only a fast-growing new category of load on the Texas grid, they can be a uniquely valuable load given their anticipated scale, the flexibilities inherent in the technology, and highly intelligent nature of their onboard, connected systems. With key clarifications in policy, investments in infrastructure, and evolution of competitive electricity market features, the charging and discharging of EVs can be intelligently managed both to benefit Texas drivers and to enhance local distribution system reliability and, by extension, ERCOT system reliability. With more than 18,000 MW of EV charging load anticipated in ERCOT little more than a decade hence, this is too large a challenge to ignore and too great an opportunity to miss.

There are several points of connection between the EV charging and the key issues in this project. First, one way to rapidly and uniformly expand EV charging infrastructure in Texas would be for DSPs to own and operate electric vehicle charging facilities (EVCFs). This could be especially important in competitive retail areas of the state where certain populations may be underserved by market-based infrastructure investment decisions such in rural or low-income areas. However, given the bi-directional electricity flow capabilities of EV batteries and charging/discharging systems, DSP-owned EVCFs could appear as a large battery resource from a system management/market interface perspective, which is directly related to the questions in this proceeding.

Second, for various technical reasons, it could be that DSPs are better situated to harness the reliability benefits of vehicle-to-grid (V2G) services than the ERCOT Independent System Operator (ISO), which directs operations of the interconnected transmission system but has significantly less visibility into the many distribution systems connected to the transmission network. In the model in which TDUs are coordinators of V2G functions rather than the owners of EVCFs, the issues in this proceeding related to TDU third party contracts for reliability services come into play.

Third, it appears there could be some key distinctions in law and policy between EVCFs in competitive choice areas of the state compared with those in NOIE service territories. As the number of EVCFs grows along with the number of Texans paying for charging service, a number of important questions will come before the Commission. Since many of those questions will be related to DSPs, they are relevant to this proceeding.

Finally, similar to our comments above regarding distribution system planning transparency for market participants, it seems to Public Citizen that if EVCF infrastructure is likely to be constructed on a large scale in the near future it would be beneficial for EVCF developers and DSPs to work collaboratively to ensure smart placement on the system. It would behoove the Commission to get in front of those policy questions and challenges rather than playing catch up after significant investment has already been made and customers have already been engaged. This project is a good place to begin that conversation.

CONCLUSION

Public Citizen appreciates the opportunity to provide these comments. We also appreciate the Commission's forward thinking in addressing these issues now. New technologies bring the promise of clean, cheap, reliable energy for Texans and will obviate the need for costly infrastructure buildouts. We believe that the approach we have recommended can be achieved under existing law without additional legislation. We urge the Commission and all participants to keep the needs of the energy consumer and the public at large in mind throughout the process.

Technology is changing rapidly, and each changes brings with it questions, potential problems, and decision points. We encourage the commission to take up the issues raised in this rulemaking again in perhaps five years, when the landscape will surely be quite different.

We welcome the opportunity to further discuss any issues raised in our comments.

Respectfully submitted,

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