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TAEBA
Texas Advanced Energy
Business Alliance

PROJECT NO. 54233

TECHNICAL REQUIREMENTS AND	§	
INTERCONNECTION PROCESSES FOR	§	PUBLIC UTILITY COMMISSION OF TEXAS
DISTRIBUTED ENERGY RESOURCES	§	
(DERS)	§	

COMMENTS OF TEXAS ADVANCED ENERGY BUSINESS ALLIANCE PROJECT NO. 54233 IN RESPONSE TO COMMISSION STAFF QUESTIONS POSTED MAY 14, 2025

Initial Comments

Texas Advanced Energy Business Alliance ("TAEBA") hereby submits these reply comments on the Commission Staff's Draft 16 Texas Administrative Code ("TAC") Rules §25.210 (newly proposed), §25.211, and §25.212 filed on May 14, 2025, in the above-referenced project. 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. Used together, these technologies and services will create and maintain a higher performing energy system—one that is reliable, 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.

TAEBA commends the Commission for revisiting Project No. 54233 and the effort it has taken to put forth proposed TAC rule changes regarding interconnection for small Distributed Energy Resources ("DERs"). We especially commend the Commission for the high quality and

clarity of the draft rule language, which reflects thoughtful consideration and regulatory leadership. These proposed rules represent a meaningful and timely advancement that will strengthen both reliability and resilience across the Texas grid. By addressing DER interconnection in a more streamlined and accessible way, the Commission is enabling more Texans to participate in and benefit from a modernized energy system – one that supports energy independence, grid flexibility, and continued job creation across the state.

TAEBA wishes to inform Commission staff of some specific concerns regarding the draft language. The most important change the Commission should consider is a separate rule for "micro-DER" systems of 50kW and below. This rule would present the opportunity for additional study efficiencies and an overall more streamlined interconnection process for DERs which have relatively low impact on distribution systems. Those efficiencies would be particularly impactful for residential customers in Texas, making the choice to build a home DER system easier for those who wish to generate their own electricity or who wish to improve their own power reliability for their home. In our attached document, TAEBA has provided some suggested changes to rule §25.211 which support this change. Though our comments related to 50kW and smaller systems were made in rule §25.211 to fit within the structure proposed by the Commission, we feel that an entirely separate rule within the TAC is the most appropriate and straightforward way to establish separate interconnection standards for these small systems, and would eliminate confusion in the procedures between systems sized 50kW and below and those for systems sized over 50kW to 250kW. In our comments filed in this same Project in 2023, TAEBA made the following statement:

> "Failure to include appropriate consideration of system size would subject very small and even behind-the-meter resources to the same standards and requirements as larger front-of-meter resources, which would create significant changes in how residential and small-scale distributed energy resources are managed and introduce overly burdensome interconnection requirements for small residential and behind-the-meter DERs without any reliability benefit or justification. While we generally support the stated need to conduct interconnection studies for large scale systems, establishing the same

requirements and processes for larger DERs and behind-the-meter DERs would negatively impact small scale systems and would put a strain on customers seeking to adopt DERs; this effect has not been observed under the current rules."[1]

TAEBA's position still aligns with this perspective today. Even relatively small systems on the distribution system can operate in vastly different ways depending on their size and intended purpose, most notably with the propensity of systems of the smallest sizes 50kW and below to be located behind the meter rather than in front of the meter. These typical differences in operation should be at the forefront of changes that the Commission makes to the rules going forward. Rules applied to systems of 50kW and below can still include stipulations for equipment safety and inter-operability standards which prevent micro-DER systems from affecting overall DSP system safety and reliability.

There is studied evidence to support these differences in interconnection requirements for micro-DER systems. From our previous comments, we presented this evidence:

"Small residential and behind the meter DERs systems are diminutive relative to even larger front-of-the-meter DERs; because of this, their impact on the system at large is likely to be negligible. Small-scale DERs should be screened only for local voltage impacts rather than subject to the same studies that apply to large-scale DERs. In removing small-scale DERs from study requirements, the Commission will improve the efficiency of the study process while still ensuring that the studies conducted capture the necessary information at sufficient granularity. TAEBA also notes that exempting small DERs from certain study requirements is consistent with the approach taken by many other states. In their review of Interconnection Practices and Costs in the Western States, the National Renewable Energy Laboratory (NREL) found that the majority of states surveyed, including Colorado, Montana, New Mexico, and Utah, have some

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[1] COMMENTS OF TEXAS ADVANCED ENERGY BUSINESS ALLIANCE ON STAFF'S DISCUSSION DRAFT, p 2-3. https://interchange.puc.texas.gov/search/documents/?controlNumber=54233&itemNumber=12

form of simplified or fast-track review processes for small DER systems.[2] States tend to screen small-scale DERs, and the report specifically found, "a few technical screens, which are used to assess feeder conditions and characteristics at the point of interconnection to determine whether a proposed project would compromise system reliability, are used for fast-track review in all states with interconnection rules."[2]

The Interstate Renewable Energy Council ("IREC") also provides best practices of how DER systems of 50kW and below can be studied under a "simplified process" for distribution system interconnection study. This process includes much shorter turnarounds on micro-DER system studies than what is proposed in rule §25.211.[3] This resource provides a step-by-step process for studying micro-DER interconnection and has served as the basis for many of the suggested changes we make in these comments.

In our previous comments, TAEBA also provided this input regarding micro-DER systems:

> "Small-scale DERs should not be subject to the insurance and termination agreement provisions included in the proposed rules. These provisions are pertinent to commercial or utility-scale DERs and the requirements are not practically achievable for small scale systems. This adjustment will greatly benefit homeowners and end users with residential-scale DERs and protect them from burdensome legal requirements which may act as barriers to their participation in the grid, harming customer choice and reliability."[4]

The Commission should consider how language addressing party responsibilities, termination of agreements, and restitution for potential harm can negatively impact micro-DER

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[2] A Guide to Updating Interconnection Rules and Incorporating IEEE Standard 1547 (2021) https://www.nrel.gov/docs/fy22osti/75290.pdf

[3] Review of Interconnection Practices and Costs in the Western States (2018) https://www.nrel.gov/docs/fy18osti/71232.pdf

[4] IREC Model Interconnection Procedures, p 15-38. https://irecusa.org/resources/irec-model-interconnection-procedures-2023/

system deployment. TAEBA has included some language changes to make clear that DER systems of 50kW and below should not be found to cause financial harm to the DSP, given this lack of clarity could have broad implications for how micro DERs are developed and how their energy offtake behaviors are governed. In the most extreme scenario, this lack of clarity could give grounds to DSPs to claim micro-DER systems which engage in peak energy shaving to lower energy costs for their load are causing financial harm to the DSP. This scenario would cool micro-DER system deployment significantly because the economics of those systems could be muddied to the point where it is unclear whether a micro-DER system will pay for itself over its lifetime. This is one example of how these agreements should be clarified, but TAEBA encourages the Commission to review the rule for any potential frictions where small customers are subject to commercial operating requirements which are not feasible for micro DER owners, particularly for residential customers using home systems for their own cost saving and reliability benefits.

In the proposed rule language, there is no mention of automation of application processing required of the DSPs. This is an opportunity for operational efficiency that should not be overlooked. Smaller systems, such as those below 50kW, can benefit from automated evaluation of both interconnection applications and interconnection studies. A provision in the new rules for this kind of automation would also enhance the human hours dedicated by the DSP to the processes of interconnection application and interconnection study assessment. Operational efficiencies of this kind also result in cost savings in the long term for both the DSPs and future interconnection customers. Automation for small-scale DERs can be tied to NRTL-certified equipment and passed screens, balancing efficiency with DSP safety needs.

TAEBA is concerned that the Commission does not include a pro forma structure for interconnection application and study fees. This omission is particularly concerning for smaller residential DER systems, which have limited opportunities for revenues which enable the DER owner to offset system cost over time, particularly where those systems are not enrolled for demand side reliability services at either the distribution or wholesale market levels. The inclusion of a pro forma interconnection fee schedule would increase customer confidence and DER system financial planning. As an example, IREC points out that a "simple" interconnection

process fee of $100-200 applies in most states, and that many states waive this fee for net metered DER facilities of 50kW and below.[5] Residential Texans would benefit from a simplified, low-cost application fee structure for their DER systems. We propose this be highlighted as a top priority in rule development, as fee transparency is critical for residential adoption.

TAEBA understands that cost sharing is not within the scope of this proposed rulemaking. We are encouraged by the Commission's willingness to explore options for interconnection and interconnection upgrade cost sharing among DER operators and owners and intend to offer examples of cost sharing models when that rulemaking opens.
Below TAEBA offers some language modifications to the proposed TAC section revisions, the proposed pro forma interconnection agreement, and addresses the specific questions posed by Commission staff in their filing. These comments are not fully inclusive of our suggested language changes, and we refer Commission staff to Attachment A included below for a full accounting of our suggested changes to Prosed Rule §25.210 and Proposed updates to Rules §25.211 and §25.212.

TAEBA Proposed Modifications to Prosed Rule §25.210 and Proposed Updated to Rules §25.211 and §25.212

In our attached file, TAEBA recommends that software qualify by default as a capable "protective function." This ensures that proven software systems which are capable of "respond[ing] to unsafe operating conditions before, during, and after the interconnection of a DER with a distribution system" will receive approval from DSPs for the grid protection functions which they are capable of, rather than leaving room for those systems to be contested for this purpose. This will allow more streamlined system operation and reduce the overall cost to interconnection customers and the grid by avoiding interconnection upgrades which are not necessary to perform safe system functions.

TAEBA also recommends requiring a 120-calendar day review period for systems above 250kW in 25.210 (f) (1). While the proposed systems testing period already has a time limit, we also find that requirements for interconnection application review will encourage DSPs to keep application reviews within a reasonable time and keep applications from building up in a

backlog. Implementing an application review timeline will also encourage DSPs to dedicate the necessary number of resources to application reviews to keep applications from sitting indefinitely.

TAEBA recommends the Commission consider the introduction of DSP hosting capacity maps ("HCMs") to allow DER interconnection applicants, particularly those with systems larger than 250kW. This allows interconnection customers to understand which circuits have available capacity to predict their interconnection costs more accurately, which also enables more effective site selection and clarifies financing needs.

TAEBA's comments also include suggested language for DER projects larger than 250kW to be developed in phases, allowing a stepped interconnection agreement process with milestone benchmarks for projects wishing to use a single interconnection agreement for projects which may necessitate a longer development timeline.

TAEBA Suggested Modifications to the Interconnection Agreement

All suggested language changes in this section are underlined for clarity.

TAEBA recommends the following language modification in Section 4 A (V): "DSP may terminate this Agreement by providing Generator at least sixty (60) calendar days' advance written notice, if practicable, in the event of a Change in Law. Upon such advance written notice, (i) DSP must cease any activities relating to the engineering or construction of the DIF or connecting the DIF to the GIF; and (ii) Parties must use commercially reasonable efforts to either amend this Agreement or execute a new agreement to reflect the Change in Law. <u>If no Agreement can be reached between the parties, the parties may petition the commission or a contracted third party to serve as an arbitrator of a new Agreement.</u>" This included provision will provide a backstop resolution for the parties if either believes the other is not negotiating in good faith to resolve issues relating to the construction of the DIF or connection of the DIF to the GIF under a change of law. All parties will benefit from a way to force an agreement under changes of law, preventing negotiations from extending out an unreasonable amount of time.

TAEBA recommends the following language modification in Section 11 H: "Each Party must establish and maintain a response plan that requires immediate response in the event of an emergency. Each Party must have a control center that is staffed twenty-four (24) hours per day, seven (7) calendar days per week, with personnel capable of operating and controlling the respective DIF and GIF by the DSP and Generator, respectively, at the POI (or make appropriate arrangements for a third-party, including for the Generator, its Qualified Scheduling Entity (QSE), to establish and maintain such a control center on a Party's behalf). For purposes of communications between the Parties' control centers or the assigned contact personnel, all contact information must be exchanged and each Party must be notified of any changes on an ongoing basis. This provision does not apply to generation systems below 50kW which are not registered with a QSE for wholesale market participation, and the emergency management of those systems is the responsibility of that system's DSP." This language clarifies that for small DER systems, the responsibility of system management in an emergency event such as system disconnection from the distribution system (i.e., "islanding") is the responsibility of the DSP and not the system owner or installer.

TAEBA recommends the following language modification in Section 13 C: "In the event of an unscheduled outage of the DER or GIF, Generator must immediately notify DSP and provide all details of the outage in writing, including GIF affected, expected duration of the outage, request for clearance, and any other relevant information as soon as practicable after the outage occurrence. Generator must update the Applicable ISO's outage scheduler, if required, in accordance with the Applicable ISO Requirements. If clearance is requested, Generator must not perform restoration of the affected GIF or DER until DSP has notified Generator that it may proceed with restoration. Following restoration of the GIF or DER, Generator must promptly notify DSP when the GIF is ready to be re-energized. Reenergization of the GIF will be coordinated among DSP, Generator, the Applicable ISO, and QSE, as necessary. This section does not apply to DER systems sized 50kW or below." TAEBA also suggests that this language should not apply to DER systems below 50kW. Requiring residential customers to provide immediate outage notification to their DSP is a burdensome and unnecessary request for the smallest DER owners. If the Commission believes outages of

this kind are of concern to the DSP, notifications should instead rely on a software system notification to provide notice of an outage.

TAEBA recommends the following language modification in Section 15 B: "Notwithstanding the provisions of Section 15(A), each Party must assume all liability for, and must indemnify each other for, any losses resulting from (i) negligence or other fault in the design, construction, or operation of their respective facilities, including the DIE GIF, and DER; or (ii) negligent acts of a Party or such Distributed Energy Resource Interconnection Agreement Page 17 Party' s representatives while such Party or its representative is located on, or is attempting to access, the other Party' s premises. Such liability includes Party' s monetary losses, costs and expenses of defending an action or claim made by a third Person, payments for damages related to the death or injury of any Person, damage to the property of the Party, payments for damages to the property of a third Person, and damages for the disruption of the business of a third Person. This paragraph does not create a liability on the part of any Party to a customer or other third Person, but requires indemnification where such liability exists. The indemnification required under this paragraph does not include responsibility for any Party' s costs and expenses of prosecuting or defending an action or claim against the other, or damages for the disruption of the business of a Party. The limitations on liability described in this Section do not apply in cases of gross negligence or intentional wrongdoing by a Party. <u>This provision does not apply to generation systems below 50kW which are not registered with a QSE for wholesale market participation.</u>" This language change clarifies that small DER systems which are not engaged in wholesale market participate cannot be found to do financial harm to their DSP. This protection is important for clarifying that "lost revenue" a DSP may incur from regular DER system operations, such as providing energy to a co-located facility or a residence cannot be considered to do financial harm to the DSP.

TAEBA Responses to Commission Staff Questions

1. "What factors and risks should the commission consider when weighing technological innovations against the need for standardized DER technical requirements, including how such standardized requirements may relate to the safety of utility personnel?"

Fortunately, there are strategies for supporting technology adoption alongside promoting safety in the face of accelerating technology innovations. The best method for blending these goals is to utilize the best industry resources available to regulators on the engineering side, by adopting pre-approval for equipment that has been certified by a National Recognized Testing Lab (NRTL), such as complying with applicable sections of UL-1741 and IEEE-1547 standards. Tying project preapproval to strict testing standards by these NRTLs allows the Commission to adopt innovative technologies iteratively and safely, without having to manually update the TAC on a revolving basis, allowing new manufacturer products or equipment types to be used as they are tested and approved.

We appreciate that staff have included such a provision in their proposed definitions of "Certified Equipment" in new rule §25.210, and in their modifications of rule §25.211 and §25.212. This ensures approved equipment lists will continue to expand without requiring direct Commission approval, while maintaining safe standards for the equipment that qualifies as preapproved for interconnection.

TAEBA also recommends a secondary pathway for independent equipment adoption through a utility review process. Under this process, the DSP would authorize the installation and operation of technologies which choose to submit to review of their explicit inclusion in the interconnection application process in the DSP's service area. Applicant technologies would qualify whether owned by a residential customer or by a third-party, provided the technology meets the following criteria:

1. The technology is qualified to be connected to the supply side of the service disconnect pursuant to the applicable provisions of the National Electric Code;
2. The technology is approved or listed by a NRTL;

3. A distribution service provider must approve or disapprove the submitted technology for installation in its service area within 60 days after a manufacturer or third-party submits a request for approval of specific models.

TAEBA submits the suggestion for a utility approval process not as a replacement or superseding process of the default approval process under the TAC language modifications recognizing NRTL certification the Commission provided, but as a supplemental process to promote faster explicit approval for individual technologies that seek it via utility review. In this way, technologies which seek to be approved under the utility authorization process will be able to seek approval in individual DSP service areas without having to defend against challenges from outside DSPs in a debate about whether they should be adopted statewide.

2. "Whether and to what extent §25.210 (>250 kW "large" DER interconnection standards) should apply to municipally-owned utilities and electric cooperatives?"

TAEBA is supportive of the Commission applying these new interconnection standards to all Distribution Service Providers ("DSPs"), including the municipally-owned utilities and electric cooperatives. Extending the provisions of this rule to all utilities, and thereby all customers in Texas, is important for maintaining the energy choice and property right freedoms of the Texan public. This provision is also important for maintaining grid reliability in the face of large projected load growth.

Conclusion

TAEBA appreciates the Commission Staff's consideration of these comments and stands ready to work with the Commission, Commission Staff, and stakeholders to make the changes necessary to ensure effective and sound technical requirements and processes for all distributed energy resources in Texas.

Respectfully submitted,

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PROJECT NO. 54233

TECHNICAL REQUIREMENTS AND INTERCONNECTION PROCESSES FOR DISTRIBUTED ENERGY RESOURCES (DERS)	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

Summary of TAEBA Recommendations to the Commission Regarding Project No. 54233 and the Proposed Distribution System Interconnection Rules

In these comments, TAEBA Provides the Commission with the following recommendations:

- The Commission should consider alternative interconnection requirements which streamline the interconnection process further for systems up to 50kW in size;
- The Commission should give DSPs firm deadlines for interconnection application reviews in addition to the deadlines for interconnection studies;
- The Commission should allow all provisions written in these proposed rules which apply to system upgrade costs to be subject to review and modification in a future rulemaking process regarding system cost sharing;
- The Commission should extend all proposed interconnection rules to all utilities including municipally-owned utilities and cooperatives, rather than just the rules for facilities larger than 250kW;
- The Commission should protect DER systems 50kW or smaller from being subject to the same liabilities as larger systems, particularly against financial harm liability, to insulate retail customers from unreasonable and burdensome costs for operating their system;
- The Commission should require DSPs to publish DER interconnection guidelines, along with associated fee schedules and hosting capacity maps on their websites;
- The Commission should seek to implement language that requires the use of automated review processes and software for application and interconnection study review where appropriate;
- The Commission should construct a pro forma fee structure for DER interconnection, including flat fees for DER interconnection applications of systems 50kW and below;
- The Commission should include a stepped application and study approach with development benchmarks for DER systems larger than 250kW.

ATTACHMENT A

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§25.210. Interconnection of Distributed Energy Resources (DERs) with a Nameplate Capacity over 250kW for Parallel Operation.

(a) **Application.**

(1) Except as provided under Public Utility Regulatory Act (PURA) § 35.037, or to the extent pre-empted by federal law, this section applies to:

(A) a distribution service provider (DSP);

(B) a distributed energy resource (DER) operator with a DER that has a nameplate capacity of over 250 kilowatts (kW) and is interconnected or is seeking to interconnect with a DSP's distribution system for parallel operations in the state of Texas; and

(C) a DER operator that is required to register with the Electric Reliability Council of Texas (ERCOT) to participate in the wholesale market.

(2) Notwithstanding paragraph (1)(A) of this subsection, this section does not apply to a municipally-owned utility (MOU) or an electric cooperative, except as provided by subsections (c)(1), (h), and (k) of this section.

(b) **Definitions.** The following words and terms when used in this section have the following meanings, unless the context indicates otherwise:

(1) **Certified equipment** -- A specific generating and protective equipment system or systems that has been certified by a National Recognized Testing Lab (NRTL) as complying with applicable sections of UL-1741 and IEEE-1547 standards, as determined by the DSP, and otherwise relates to safety and reliability when

paralleling with the grid at the time of interconnection. The Commission will consider updates to the above NRTL standards on a five-year basis.

(2) **Commercial operations date** – The date that a generator has completed all steps necessary to legally perform the listed services in the interconnection application.

(3) **Distributed natural gas generation facility** -- A DER that uses natural gas to generate not more than two megawatts (MW) of electricity.

(4) **Distribution energy resource (DER)** -- A source of electric power interconnected at a voltage less than 60 kilovolts (kV).

(5) **DER operator--** Any entity operating a DER or seeking to interconnect a DER in Texas.

(6) **In-service date** – The date that the DSP's interconnection facilities will be constructed and ready for the DER to start using the DSP's facilities to interconnect the DER to the DSP's distribution system.

(7) **Interconnection** -- The physical connection of a DER to a distribution system to enable parallel operation with the distribution system.

(8) **Interconnection agreement** -- The commission-prescribed contractual agreement under subsection (l) of this section.

(9) **Interconnection application** – The commission-prescribed form under subsection (m) of this section.

(10) **Network** – Consists of two or more primary distribution feeder sources electronically tied together on the DSP's secondary (or low voltage) side to form one power source for one or more customers.

Commented [A1]: TAEBA suggests this language to encourage the examination and possible adoption of updated NRTL standards in the future.

(11) **Parallel operation** -- The operation of a DER while the DER is interconnected to the distribution system.

(12) **Point of interconnection (POI) --** The point where the electrical conductors of the distribution system are interconnected to a DER's conductors and where any transfer of electric power between the DER and the distribution system takes place, such as the switchgear near the meter.

(13) **Protective function** – A function carried out using hardware or software that is designed to respond to unsafe operating conditions before, during, and after the interconnection of a DER with a distribution system. For purposes of this definition, unsafe operating conditions are conditions that, if left uncorrected, would result in harm to personnel, damage to equipment, unacceptable system instability or operation outside legally established parameters affecting the quality of service to other customers connected to the distribution system.

Commented [A2]: TAEBA recommends this language change to reflect a default condition where software is permitted to function as a "protective function", where that software is proven to prevent harm to personnel and equipment, and proven to prevent unacceptable system instability or operation outside legal parameters.

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(c) **Requirement for interconnection of a DER.** A DER may be interconnected with a DSP's distribution system if the criteria of this subsection are met and maintained on an ongoing basis.

(1) A DER operator must comply with the technical and operational requirements of § 25.212 of this title (relating to Technical and Operational Requirements for Parallel Operation of Interconnected Distributed Energy Resources (DERs)).

(2) For each DER, a DER operator must have:

(A) a currently effective executed interconnection agreement with the DSP that provides all of the required information about the DER; and

(B) permission to operate from the DSP following successful commissioning and testing.

(d) **Terms of service.** A DSP must provide service to an interconnected DER under the following terms.

(1) **Prohibited costs.** A DSP is prohibited from charging a DER operator fees for the disconnection of a DER at the order of a DSP in accordance with clauses (2)(A)-(E) of this subsection.

(2) **Disconnection and reconnection.** A DSP may only disconnect a DER from the DSP's distribution system in accordance with the conditions of this paragraph.

(A) **Termination of interconnection agreement.** Upon expiration or termination of the executed interconnection agreement with the DER operator, the DSP may disconnect the DER in accordance with the terms of the executed interconnection agreement.

(B) **Safety and reliability issue caused by DER.** For purposes of this subparagraph, a "safety and reliability issue" means an issue that represents a threat to public safety, the safety of the DSP's or DER operator's personnel, the safety of the DSP's customers, or to the reliability and continuity of electric service.

(i) Upon discovery of a safety or reliability issue the DER operator or DSP must immediately disconnect the DER from the distribution system and notify the other party of the disconnection.

(ii) If the interconnected DER is the cause of a safety or reliability issue, such an issue must be resolved prior to re-interconnection and a DSP may require the following in accordance with subsections (f) of this section:

(I) a new impact study to be performed;

(II) the executed interconnection agreement to be revised; or

(III) additional testing to be conducted.

(C) **DER non-compliance.** If at any time a DER no longer meets the interconnection requirements listed under subsection (c) of this section, then a DSP must disconnect the DER. Upon notification from the DER operator that the DER has been restored to compliance with the requirements listed under subsection (c) of this section, the DSP must

(i) verify such compliance prior to reconnection as quickly as is reasonably practicable, but not to exceed 10 working days; and

(ii) upon verification, the DSP must reconnect the DER and notify the DER operator of the reconnection.

Commented [A3]: TAEBA recommends shortening the review time for compliance verification from 15 to 10 working days because two working weeks is a significant cost to a DER system's operations, and DSP review can reasonably take place within this timeframe barring significant system interruptions.

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(D) **System emergency causing an unscheduled outage.** A DSP may temporarily disconnect a DER when directed by the reliability coordinator or independent system operator, as applicable, to shed load or during an unscheduled outage of a DSP's distribution system.

(i) During and after an unscheduled outage of a DSP's distribution system the DSP must, as quickly as is reasonably practicable:

(I) notify the DER operator of an unscheduled outage of the DSP's distribution system that affects the DER;

(II) initiate repairs if any; and

(III) reconnect the DER.

(ii) During an unscheduled outage due to load shed directed by the reliability coordinator or independent system operator, as applicable, the DSP must reconnect the DER as soon as reasonably practicable while abiding by the commission's rules for reconnecting customers designated as critical customers under § 25.497 of this title (relating to Critical Load Industrial Customers, Critical Load Public Safety Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers) or critical loads under §25.52 of this title (relating to Reliability and Continuity of Service).

(E) **Scheduled outages for routine maintenance, repairs, and modifications.** A DSP may temporarily disconnect a DER from the DSP's distribution system for a scheduled outage, provided that the DSP issues notice in writing to the DER operator at least seven working days prior to such a disconnection. The DSP must reconnect the DER as quickly as is reasonably practicable and notify the DER operator following any such service interruption.

(3) **Tariff updates.** Not later than 30 calendar days after the effective date of this section, a DSP that is also a transmission and distribution utility (TDU) must file a tariff amendment with the commission that complies with this section.

(4) **New or amended interconnection agreements.** Newly executed or amendments to currently effective interconnection agreements must meet the requirements of this section within:

(A) 30 calendar days after the approval of a compliance tariff for a DSP that is also a TDU is approved by the commission, or

(B) 90 calendar days after the adoption of this section for a DSP that is not is not a TDU.

(5) **Fee Schedule.** DSPs must publish a fee schedule on its website.

(A) The fee schedule must include the cost of a prescreen study and the cost of an impact study, and must be easily accessible on the DSP's website related to DERs.

(B) The fee schedule published on the DSP's website must be clearly labeled as only applying to DERs larger than 250kW.

(C) DSPs must publish a DER Interconnection guide including interconnection fee schedules on its website.

(D) DSPs shall publish and annually update hosting capacity maps for each feeder and substation, indicating approximate available export and load capacity for DERs >250 kW.

Commented [A4]: This language is recommended to ensure DSPs include clear interconnection guidelines with an associated fee schedule, which will enable interconnection customers to better understand the interconnection requirements and more accurately assess system installation costs.

Commented [A5]: TAEBA suggests this language to encourage efficient project siting and to avoid speculative pre-screen studies.

(c) **Pre-screen study.** A DER operator may request a pre-screen study for one or more proposed sites for a DER prior to submitting an interconnection application under subsection (f) of this section. A pre-screen study must be performed in accordance with good utility practice. A pre-screen study does not represent a commitment to procure or utilize particular equipment, either by the DSP or the DER operator, and does not change the requirement for an impact study. A pre-screen study will not, on its own, reserve or hold capacity on the distribution system.

(1) The DER operator must provide the DSP the following, at a minimum, to initiate a pre-screen study:

(A) the intended operation of the DER, such as a dispatchable resource for energy or ancillary services with an independent system operator, a settlement only generator with ERCOT, or only to be used as on-site back-up power;

(B) the proposed commercial operations date of the DER;

(C) the type of generator equipment;

(D) the GPS coordinates or address of the requested POI, the DER, and the interconnecting substation;

(E) the nameplate capacity of the DER;

(F) the fuel source of the DER;

(G) the approximate generation exporting level; and

(H) if the DER is an energy storage resource, then the approximate load charging level.

(2) A DSP's results from a pre-screen study are estimations and the DSP is not required to complete a detailed engineering analysis or provide a detailed cost estimate. A DSP's results from a pre-screen study must:

(A) indicate whether the requested operations, generation exporting level, and as applicable load charging level, of the DER can be accommodated at the DSP's applicable distribution feeder and substation;

(B) identify known potential limitations on the DSP's distribution system;

(C) list the additions or upgrades needed to accommodate interconnection of the DER at the DSP's substation which may include a new feeder, substation, and any additional bay requirements, transformer replacements in an existing substation, or another major modification to the existing substation known by the DSP;

(D) identify the distance to the nearest substation from the requested POI provided by the DER operator; and

(E) provide the prevalent distribution voltage at the requested POI the DER operator submitted to the DSP to study.

(3) All DERs with executed and fully-funded interconnection agreements must be included when conducting the requested pre-screen study.

(4) The DSP must perform a pre-screen study once the DSP has received all the documentation required by the DSP and payment from the DER operator for the pre-screen study.

(A) A pre-screen study is undertaken as of a stated date and a DSP must use best efforts to provide the results of a pre-screen study within 15 working days of that stated date, but not to exceed 30 working days.

(B) Such time may be extended if a DER operator and its affiliates collectively request pre-screen studies for more than ten sites currently pending with the DSP, or if the total number of pre-screen studies pending with the DSP exceeds ten sites.

(B) If the pre-screen study involves interconnection to a network, the pre-screen may take an additional ten working days to complete.

(f) **Interconnection Process.** A DSP must permit a DER operator to interconnect any DER that meets the requirements of § 25.212 of this title and has successfully met the requirements of paragraphs (1)-(4) of this subsection.

(1) **Interconnection application.** To initiate the interconnection process, a DER operator must submit to the DSP a completed interconnection application and all supporting documentation necessary for a DSP to conduct an impact study as required by paragraph (2) of this section. A DSP must review the interconnection application and supporting documentation for completeness and adherence to all applicable technical criteria. A DSP must complete this application review within 120 caledar days. Upon concluding its review, the DSP must approve, suspend, or reject the interconnection application, and promptly notify the DER operator of the decision in writing.

Commented [A6]: TAEBA recommends setting a time turnaround up front to keep interconnection applications from lingering in the review process indefinitely. We believe 120 calendar days is a reasonable turnaround for larger DER systems.

(A) The DSP must promptly notify the DER operator in writing of any deficiencies in the interconnection application or supporting documentation and provide a reasonable timeframe to cure the deficiencies.

(B) An interconnection application is deemed withdrawn if a DER operator submits a notice of termination to the DSP.

(C) A DSP may reject an interconnection application if:

(i) The DSP can demonstrate specific reliability or safety reasons indicating why the DER should not be interconnected at the requested site, which must be communicated to the DER operator in writing;

(ii) The DER operator fails to timely remit payment for the impact study to the DSP under subparagraph (2)(A) of this subsection; or

(iii) The DSP cannot accommodate the capacity requested by a DER operator because of capacity reserved by the DSP to support necessary planned projects.

(I) Planned projects must have an executed agreement for energization with the DSP. Such agreements must have an energization date within two years of the DER submitting its interconnection application.

(II) Upon request, the DSP must provide such agreements within 15 calendar days. The DSP may redact confidential information, as applicable.

(D) A DSP may suspend an interconnection application if more than one impact study application at the same substation is under review by the DSP.

(i) The DSP must notify the DER operator of the suspension and provide an estimated timeline for resuming review of the interconnection application in writing as soon as is reasonably practicable. Suspensions must be justified in writing, limited to no more than 60 calendar days, and may be appealed by the DER operator to the Commission for expedited resolution.

Commented [A7]: TAEBA includes this modification to provide some recourse to interconnecting DERs and prevent arbitrary delays targeting 3rd-party DERs.

(ii) The DSP must resume its review of the interconnection application based on the order in which the applications were deemed complete and in adherence with all applicable technical criteria.

(2) **Impact Study.** An impact study may consist of one or more service studies, coordination studies, distribution system impact studies, or other studies as determined by the DSP. After approval of a DER operator's interconnection application under paragraph (1) of this subsection, a DSP must complete an impact study of the DER in accordance with the details provided in the interconnection application and this paragraph. In performing an impact study, a DSP must review reasonable methods to safely and reliably interconnect a DER with the distribution system which, for certain DERs, may include options other than the standard radial feed, as determined by the interconnecting DSP.

(A) Upon determination by a DSP that an interconnection application is approved, the DSP must notify the DER operator in writing. The notice will also include any additional technical studies that are required by the DSP.

The DSP must proceed with the impact study after receipt of the study fee from the DER operator.

(B) The DSP must use good-faith efforts to complete the impact study and provide the study results to the DER operator within 60 working days, but not to exceed 90 working days, after the DSP's receipt of the study fee.

(i) Timelines may be extended if a DER operator and its affiliates collectively request studies for more than ten sites currently pending with the DSP, or if the total number of impact studies pending with the DSP exceeds ten sites.

(ii) If the DER operator's proposed interconnection is to a network, the timeline will be extended to 120 working days after the DSP's receipt of the study fee.

(C) The results of an impact study must include:

(i) a list of impact study assumptions, including the allowable physical operating capabilities of the DER;

(ii) details of any required facilities or upgrades needed to interconnect the DER at its requested service level;

(iii) an estimate of the itemized costs of any required facilities or upgrades needed to allow parallel operation of the DER which should contain, at a minimum, a description of and estimated costs for distribution system upgrades, a description of and estimated costs for substation upgrades, any applicable allowance for interconnection as provided in the DSP's tariff, and applicable fees

and taxes, to the extent the DSP is able to determine this information for the particular DER;

(iv) the amount of such costs the DSP requires to be covered by a contribution in aid of construction (CIAC); and

(v) a list of additional devices, operating schemes, or other specifications that, as determined by the DSP, may be required for interconnection of the DER described in an interconnection application.

(D) No later than 30 working days following the DER operator's receipt of the impact study results, the DER operator must issue a notice to proceed to the DSP that indicates in writing whether the DER operator plans to proceed with the interconnecting the DER.

(E) The DSP may require a new impact study to be performed at the DER operator's expense if, after beginning the initial impact study of the DER, there are any unexpected changes to the DER's commercial operations date, design configuration, equipment (including the make and model of any components), operational requirements, or easement requirements that would potentially change the results of the initial impact study. The DSP may require a new impact study be performed at the DER operator's expense if, within 60 working days following the DER provider's receipt of the impact study results:

(i) An interconnection agreement has not been executed in accordance with paragraph (3) of this subsection.

(ii) The DER operator has not provided the DSP a CIAC as required by paragraph (g)(3) of this section.

(iii) The DER operator has not demonstrated it has secured all necessary authorization or ownership to build at the selected location.

(iiii) A DER operator's queue position shall not be forfeited due to reasonable site adjustments (e.g., relocating the point of interconnection within the same feeder or substation area) unless the DSP demonstrates that such changes materially impact system reliability or study results.

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Commented [A8]: This language protects third-party investment against unnecessary queue delays due to non-material project refinements.

(3) **Interconnection Agreement.** After completion of an impact study and the notice to proceed has been issued by the DER operator, the DSP and the DER operator must execute an interconnection agreement to proceed with interconnecting the DER.

(A) Within 15 working days of the date the DER operator issues the notice to proceed, the DSP must provide an interconnection agreement to the DER operator that includes the estimated in-service date for the DSP's interconnection facilities.

(i) The in-service date may be contingent on the receipt of the items listed in subclauses (ii)(I) and (ii)(II) of this subparagraph.

(ii) The DSP must commence construction by no later than 60 calendar days after the DSP's receipt of the following items, as applicable:

(I) evidence that all necessary easements have been obtained by the DER operator, and

(II) payment of the CIAC by the DER operator to the DSP.

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(B) The interconnection agreement may be modified upon the DSP's and DER operator's mutual agreement.

(i) Modifications to an interconnection agreement must be consistent with the requirements of this section, §25.212 of this title, and, as applicable, rules and protocols established by the applicable independent system operator and regulatory authority. Any modifications to an interconnection agreement that conflict with the applicable law are void.

(ii) If the modified interconnection agreement contains substantially different terms or conditions than those provided in the standard form interconnection agreement, then the DSP must file with the commission the executed version of the modified, amended, or revised interconnection agreement within 30 calendar days of the execution. A cover letter must be included summarizing the contents of the amendments. Portions of an executed interconnection agreement may be filed confidentially to protect critical energy infrastructure information and competitively sensitive commercial or financial information.

(C) The DSP may terminate an executed interconnection agreement if the DER operator is unable meet the commercial operations date and begin providing the services the DER operator sought through the interconnection agreement within 12 months after the DER's stated in-service date that is

provided in the interconnection agreement and as adjusted day-by-day for any delay in the DSP meeting the in-service date. DER operators developing projects in phases may enter into a single interconnection agreement covering the full project scope, with milestone in-service dates and cost allocations per phase.

Commented [A9]: This language adds interconnection agreement procedure clarity for DER systems which are developed in phases. This provides contractual flexibility and supports financing.

(4) **Testing.** The DER operator and DSP must coordinate to complete all interconnection and interoperability equipment testing before the commercial operations date specified in the executed interconnection agreement.

(A) The DER operator must provide notice to the DSP at least 15 calendar days before the initial energizing, start-up testing, and any interoperability testing of the DER. The DSP may observe the testing of any equipment and protective systems associated with the interconnection.

(i) Testing of protection systems must include procedures to functionally test all protective elements and telemetry equipment of the DER up to and including tripping of the DER at the point of interconnection. Testing must verify an established communication signal for telemetry to the DSP, all protective set points, and breaker trip timing. The DSP may have specific testing requirements and may observe the testing of the DER, including installed switchgear and protection systems.

(ii) If modifications to a DER are deemed to be necessary by a DSP or DER operator after testing of the DER under this paragraph, a DER operator must submit a revised interconnection application to the

DSP within fifteen working days with information reflecting any necessary or foreseeably necessary modifications to the DER. A DSP may only deem a modification to be necessary if the safe and reliable operation of the DSP's distribution system may be impacted or if the modification is otherwise required by law, including local ordinances or codes.

Commented [A10]: Though proposed DER modifications may be limited after testing, TAEBA believes that fifteen working days is a more reasonable turnaround for a modified project proposal.

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(B) A DSP may require additional testing of the DER upon any modifications of the DER or protective functions after the commencement of commercial operations. A DSP must not require additional testing of the DER if modifications are a replacement of like-for-like components.

(g) **Responsibilities during and after interconnection.**

(1) **Communications.** A DER operator must provide the DSP with complete and detailed written information concerning the proposed DER during each stage of the interconnection process.

(A) A DER operator and DSP must provide updates to each other as quickly as possible, and no later than two working days thereafter each time the DER operator or DSP becomes aware of a change to the expected timeline for interconnection that is expected to impact the in-service date or commercial operations date under the interconnection agreement.

(B) Timelines stipulated in this section can be extended, as necessary, if agreed upon in writing by the DSP and DER operator. Communications concerning the DER must be consistent with § 25.84 of this title (relating to Reporting

of Affiliate Transactions for Electric Utilities), § 25.272 of this title (relating to Code of Conduct for Electric Utilities and their Affiliates), and § 25.273 of this title (relating to Contracts between Electric Utilities and their Competitive Affiliates).

(2) **Anticompetitive practices prohibited.** A DSP and its affiliates must not use knowledge of a proposed DER submitted to it for pre-screen study, impact study, or interconnection to prepare competing proposals to the DER operator that offer either discounted rates in return for not installing the DER, or offer competing DERs. Furthermore, a DSP must not use this information for any purpose other than its intended purpose without the written agreement of the DER operator. A DSP or its affiliate may not propose or construct a utility-owned BESS or DER at a location for which a third-party DER has an active application, study, or executed agreement, unless the DSP can demonstrate no preferential access to interconnection data or system upgrades. DER interconnection rights and agreements may be assigned or transferred to a successor owner or operator upon notice to the DSP, provided that technical and financial capabilities remain substantially similar.

(3) **Contribution in aid of construction.** Notwithstanding any other law, a DSP may require a CIAC from a DER operator for the reasonably estimated, detailed costs that a DSP incurs to design, procure, construct, install, or upgrade interconnection facilities that are necessary to operate the DER at the impact study determined service level which may include transmission system upgrades and such facilities inside the DSP's substation, and for the costs of any acquisitions of the additional

Commented [A11]: This language is included to ensure additional protection against anti-competitive actions, leveling the playing field between DSP and third-party DER project development.

Commented [A12]: This suggested language change supports investment liquidity and tax equity transfer deals.

Commented [A13]: With the promise of addressing cost sharing and responsibilities in another project number, TAEBA is not addressing this section in these comments. However, we urge the Commission to consider all suggested modifications to this section under future rulemaking proceedings where cost sharing is deemed to be in scope.

facilities required by the DSP for safe and reliable interconnection of the DER. Such costs are limited to those specified in an executed interconnection agreement and, if applicable, exceed any allowance for interconnection in accordance with the DSP's tariff.

(A) The DSP must provide the DER operator an estimation of the itemized costs to be collected through the CIAC, which must contain, at a minimum, a description of, and estimated costs for, distribution system upgrades including for substation upgrades, any applicable allowance for interconnection as provided in the DSP's tariff, and applicable fees and taxes, to the extent the DSP is able to determine this information for the particular DER. The DSP must provide this estimation of the itemized costs consistent with its tariff and the DSP's standard process for addressing other load-serving costs as applicable.

(B) A DSP must reconcile invoices for the total DSP upgrade costs with the total CIAC payment made by the DER operator within 180 calendar days from the date the DSP is notified that the DER is commencing commercial operations. A DSP must provide this reconciliation to the DER operator for the facilities the DSP procured and installed to enable the DER to interconnect to the distribution system.

(i) If the invoiced amounts are less than the sum of the CIAC and any allowance provided in accordance with the DSP's tariff, then the DSP must reimburse the DER operator all excess funds the DER operator paid the DSP. The DSP must provide a detailed itemization

of actual costs incurred during construction upon reconciliation. DER operators shall have the right to dispute cost overruns exceeding 10% of the original impact study estimate.

Commented [A14]: This suggested language limits cost inflation risk for third-party owners and ensures equitable CIAC reconciliation.

(ii) If an allowance provided in accordance with the DSP's tariff, exceeds the DSP's interconnection costs, then the DSP will not reimburse the DER operator any amount of an allowance.

(h) **Reporting Requirements.**

(1) Each DSP must maintain records concerning applications received for interconnection and parallel operation of DERs. Such records must include:

(A) the name of the applicant;

(B) the business address of the applicant;

(C) the location of the proposed facility by county;

(D) the capacity rating of the facility in kilowatts;

(E) whether the facility is a renewable energy resource as defined in § 25.173 of this title (relating to Goal for Renewable Energy);

(F) the date each application is received;

(G) documents generated in the course of processing each application;

(H) correspondence regarding each application; and

(I) the final disposition of each application.

(2) The owner of a DER facility that is interconnected under this section must report to the DSP any change in ownership of the facility and the cessation of operations of a facility within 14 working days of such change.

(3) By March 30 of each calendar year, each DSP must file with the commission the commission-prescribed reporting form under subsection (n) of this section. The form must be filed in native Microsoft Excel format and must permit basic data manipulation functions, such as copying and pasting of data. The report will list:

(A) the new DER facilities interconnected with the system since the previous year' report;

(B) any change in ownership or the cessation of operations of any DER that has been reported to the DSP and not included in the previous report;

(C) the capacity of each facility and whether it is a renewable energy resource;

(D) the feeder or other point on the DSP's distribution system where the facility is interconnected; and

(E) all applications for interconnection received during the previous one-year period, and the disposition of such applications.

(i) **Distributed natural gas generation facility.** This section applies only to a DER that is a distributed natural gas generation facility geographically located within the ERCOT power region.

(1) Upon request of an owner or operator of a distributed natural gas generation facility, a DSP must:

(A) allow the owner or operator to interconnect with and utilize transmission and distribution facilities to transmit electricity to another entity that is acceptable to the owner or operator; and

(B) comply with Chapter 25, Subchapter I, Division 1 §§ 25.191–25.203 (relating to Open- Access Comparable Transmission Service for Electrical Utilities in the Electric Reliability Council of Texas) of this title, or a tariff approved by the Federal Energy Regulatory Commission (FERC)

(2) In the event that a DSP seeks to recover an amount in excess of the estimate provided under PURA § 35.036(e) by more than 5%, an owner or operator of a distributed natural gas generation facility may petition the commission to address the discrepancy.

(3) This subsection does not require an electric cooperative to transmit electricity to a retail POI in the certificated area of the electric cooperative if the electric cooperative has not adopted customer choice.

(j) **Alternative requirements and standards.** An independent system operator may establish interconnection requirements and standards for interconnecting DERs in addition to the requirements and standards prescribed under this section.

(k) **Open access tariff.** Within one year from the effective date of this rule, a DSP, including an MOU or electric cooperative, must file with the commission a nondiscriminatory open access tariff for wholesale transmission service at distribution voltage. The tariff must:

(1) provide for open access to the DSP's distribution system; and

(2) establish nondiscriminatory terms of access that are comparable to the rates and terms of the DSP's use of its system.

(l) **DER Interconnection Agreement.** Figure: 16 TAC § 25.210(l)

(m) **Application for Interconnection of a DER.** Figure: 16 TAC § 25.210(m)

(n) **Annual DER Report.** Figure: 16 TAC § 25.210(n)

§25.211. Interconnection of Distributed Energy Resources (DERs) with a Nameplate Capacity of 250kW or Less for Parallel Operation.

(a) **Application.** Unless the context indicates otherwise, this section applies to an electric utility and a customer that owns or operates a distributed energy resource (DER) that has a nameplate capacity of 250 kilowatts (kW) or less and is interconnected or seeking interconnection, except to the extent preempted by federal law.

(1) This section establishes the terms and conditions that govern the interconnection and parallel operation of DERs to implement Public Utility Regulatory Act (PURA) §39.101(b)(3) and a natural gas distributed generation facility to implement PURA §35.036.

(2) Sales of power by on-site DER and distributed natural gas generation facility in the intrastate wholesale market are subject to Subchapter I, §§25.191-25.203 of this chapter (relating to Open-Access Comparable Transmission Service for Electrical Utilities in the Electric Reliability Council of Texas).

(3) The only part of this section that applies to an electric cooperative is subsection (n) of this section, as applicable.

(b) **Definitions.** The following words and terms when used in this section have the following meanings, unless the context indicates otherwise:

(1) **Certified equipment** – A specific generating and protective equipment system or systems that has been certified by a National Recognized Testing Lab (NRTL) as complying with applicable sections of UL-1741 and IEEE-1547 standards, as

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determined by the DSP and relating to safety and reliability when paralleling with the grid at the time of interconnection. The Commission will consider updates to the above NRTL standards on a five-year basis.

(2) **Company** -- An electric utility operating a distribution system.

(3) **Customer** -- Any entity that owns or operates a DER that is 250kw or less, not registered with ERCOT, and is interconnected or seeking interconnection to a company's distribution system.

(4) **Distributed energy resource (DER)** -- A source of electric power connected at a voltage of less than 60 kilovolts (kV).

(5) **Distributed natural gas generation facility** -- A DER installed on the customer's side of the meter that uses natural gas to generate not more than 2,000 kilowatts of electricity.

(6) **Distribution system** -- A company's system operating under 60 kV.

(7) **Facility** -- An electrical generating installation consisting of one or more on-site DER units, including a distributed natural gas generation facility.

(8) **Interconnection** -- The physical connection of a DER to a distribution system to enable parallel operation.

(9) **Interconnection agreement** -- The commission-prescribed contractual agreement under subsection (p) of this section. DERs that have nameplate capacity under 50 kW or export capacity under 25 kW, using certified equipment and protective devices, may use a simplified commission-prescribed application form under subsection (-) of this section and the fast track application review and approval process under subsection (-) of this section.

Commented [A15]: Modification made in accordance with our comments in section §24.210.

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Commented [A17]: TAEBA includes this section of the interconnection agreement to allow for a separate "simplified" interconnection process for systems 50kW and below.

(10) **Interconnection application** -- The commission-prescribed form under subsection (q) of this section.

(11) **Network** -- Two or more primary distribution feeder sources electrically tied together on the secondary (or low voltage) side to form one power source for one or more customers.

(12) **Parallel operation** -- The operation of a DER while the DER is interconnected to the distribution system.

(13) **Point of interconnection (POI)** -- The point where the electrical conductors of the company's distribution system are connected to the customer's conductors and where any transfer of electric power between the customer and the company's distribution system takes place, such as switchgear near the meter.

(14) **Pre-interconnection study** -- A study or studies that may be undertaken by a company in response to its receipt of a completed application for interconnection and parallel operation with the company's distribution system. Pre-interconnection studies may include, but are not limited to, service studies, coordination studies and system impact studies.

(15) **Protective function** -- A function carried out using hardware and, potentially, software that is designed to respond to unsafe operating conditions before, during, and after the interconnection of a DER with a distribution system. For purposes of this definition, unsafe operating conditions are conditions that, if left uncorrected, would result in harm to personnel, damage to equipment, unacceptable system instability or operation outside legally established parameters affecting the quality of service to other customers connected to the distribution system.

(16) **Unit** -- A power generator.

(c) **Terms of Service.**

(1) **Distribution line charge.** No distribution line charge will be assessed to a customer for exporting energy to the distribution system.

(2) **Interconnection operations and maintenance costs.** No charge for operation and maintenance of a distribution system's facilities will be assessed against a customer for exporting energy to the distribution system.

(3) **Transmission charges.** No transmission charges will be assessed to a customer for exporting energy. For purposes of this paragraph, the term "transmission charges" means transmission access and line charges, transformation charges, and transmission line loss charges.

(4) **New or amended interconnection agreements.** A new or amended interconnection agreement entered into 30 or more days after the commission's approval of a company's compliance tariff filed in accordance with paragraph (5) of this subsection must meet the requirements of this section.

(5) **Tariffs.** Not later than 30 days after the effective date of this amended section, a company must file with the commission for approval tariff amendments to comply with this amended section, including the interconnection agreement under subsection (p) of this section and the interconnection application under subsection(q) of this section. A company must include in its tariff the fees for interconnection studies. A company that sells electricity must also include back-up, supplemental, and maintenance power services for DERs in its tariff.

(d) Interconnection review, requirements and processing.

(1) The following shall apply to applications for DER facilities up to and including 50 kW or with an export capacity up to 25 kW:

A. Interconnection Review. For DER applications with a capacity of up to 50 kW, or up to 25 kW of export capacity, approval for interconnection shall be processed not later than two weeks following the company's receipt of:

(i) a completed interconnection request including all supporting documents and required fees set forth in the standard interconnection tariff;

(ii) a completed signed interconnection agreement; and

(iii) evidence of applicant's final electric inspection clearance from an applicable local authority having jurisdiction over the proposed facility.

If the two week interconnection approval period cannot be met, the distribution provider shall notify the applicant and the commission of the reason for the inability to process the interconnection request and the expected completion date.

(d) **Disconnection and reconnection.** A company may disconnect a DER unit from the distribution system under the following conditions:

(1) **Expiration or termination of interconnection agreement.** The interconnection agreement specifies the effective term and termination rights of the company and customer. Upon expiration or termination of the interconnection agreement with a customer, in accordance with the terms of the agreement, the company may disconnect customer's facilities.

(2) **Non-compliance with the technical requirements specified in §25.212 of this title.** A company may disconnect a DER facility if the facility is not in compliance

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Commented [A18]: TAEBA also includes this section of the interconnection agreement to allow for a separate "simplified" interconnection process for systems 50kW and below.

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with the technical requirements specified in §25.212 of this title. Within two working days from the time the customer notifies the company that the facility has been restored to compliance with the technical requirements of §25.212 of this title, the company will have an inspector verify such compliance. Upon such verification, the customer, in coordination with the company, may reconnect the facility.

(3) **System emergency.** A company may temporarily disconnect a customer's facility without prior written notice in cases where continued interconnection will endanger persons or property. During the forced outage of a distribution system, the company will have the right to temporarily disconnect a customer's facility to make immediate repairs on the distribution system. When possible, the company will provide the customer with reasonable notice and reconnect the customer as quickly as reasonably practical.

(4) **Routine maintenance, repairs, and modifications.** A company may disconnect a customer or a customer's facility with seven working days prior written notice of a service interruption for routine maintenance, repairs, and distribution system modifications. The company will reconnect the customer as quickly as reasonably possible following any such service interruption.

(5) **Lack of approved application and interconnection agreement.** In order to interconnect DER to a distribution system, a customer must first submit to the company an application for interconnection and parallel operation with the distribution system and execute an interconnection agreement on the forms prescribed by the commission. The company may refuse to connect or may

disconnect the customer's facility if such application has not been received and approved.

(e) **Incremental demand charges.** During the term of an interconnection agreement a company may require a customer to disconnect its DER unit or take the DER unit off-line as a result of distribution system conditions described in subsection (d)(3) and (4) of this section. Incremental demand charges arising from the disconnection of the DER as directed by the company during such periods will not be assessed by the company to the customer.

(f) **Pre-interconnection studies for non-network interconnection of DERs.** A company may conduct a service study, coordination study or system impact study prior to interconnection of a DER facility. In instances where such studies are deemed necessary, the scope of such studies must be based on the characteristics of the particular DER facility to be interconnected and the company's distribution system at the specific proposed location. By agreement between the company and the customer, studies related to the interconnection of on-site DER on the customer's premises may be conducted by a qualified third party.

(1) **DER facilities for which no pre-interconnection study fees may be charged.** A company may not charge a customer a fee to conduct a pre-interconnection study for a DER using certified equipment that export not more than 15% of the total load on a single radial feeder and contribute not more than 25% of the maximum potential short circuit current on a single radial feeder.

(2) **DER facilities for which pre-interconnection study fees may be charged.** Prior to the interconnection of a DER facility not described in paragraph (1) of this subsection, a company may charge a customer a fee to offset the company's costs incurred in the conduct of a pre-interconnection study. In those instances where a company conducts a pre-interconnection study the following must apply:

(A) The conduct of such pre-interconnection study must take no more than four weeks;

(B) A company must prepare written reports of the study findings and make them available to the customer;

(C) The company must consider both the costs incurred and the benefits realized as a result of the interconnection of the DER to the company's distribution system; and

(D) The customer must receive an estimate of the study cost before the company initiates the study.

(g) **Network interconnection of DERs.** In instances where a customer requests interconnection to a secondary network system, the company and the customer must use reasonable efforts to complete the interconnection and the company must utilize the following guidelines:

(1) A company must approve applications for DER facilities that use inverter-based protective functions unless total generation (including the new facility) on affected feeders represents more than 25% of the total load of the secondary network under consideration.

(2) A company must approve applications for other on-site generation facilities whose total generation is less than the local customer's load unless total generation (including the new facility) on affected feeders represents more than 25% of the total load of the secondary network under consideration.

(3) A company may postpone processing an application for a DER facility under this section if the total existing generation on the targeted feeder represents more than 25% of the total load of the secondary network under consideration. In such an event, the company must conduct interconnection and network studies to determine whether, and in what amount, additional DER facilities can be safely added to the feeder or accommodated in some other fashion. These studies must be completed within six weeks from the completion of the additional studies, and application processing should then resume. If an interconnection application is delayed, the customer must be informed in writing within ten calendar days of the delay and be provided an estimated interconnection date.

(4) A company may reject applications for a DER facility under this section if the company can demonstrate specific reliability or safety reasons why the DER should not be interconnected at the requested site. In such an event, the company must work with the customer to attempt to resolve such problems to their mutual satisfaction.

(5) A company must make all reasonable efforts to seek methods to safely and reliably interconnect DER facilities that will export power. This may include switching service to a radial feed if practical and if acceptable to the customer.

(h) **Pre-Interconnection studies for network interconnection of DERs.** Prior to charging a pre-interconnection study fee for a network interconnection of a DER, a company must first advise the customer of the potential problems associated with interconnection of a DER with its network system. For potential interconnections to network systems there will be no pre-interconnection study fee assessed for a facility with inverter systems under 50 kW. For all other facilities the company may charge the customer a fee to offset its costs incurred in the conduct of the pre-interconnection study. In those instances where a company conducts a pre-interconnection study, the following requirements apply:

(1) The conduct of such pre-interconnection studies must take no more than four weeks;

(2) A company must prepare written reports of the study findings and make them available to the customer;

(3) The studies must consider both the costs incurred and the benefits realized as a result of the interconnection of the DER to the company's distribution system; and

(4) The customer must receive an estimate of the study cost with estimates itemized, before the company initiates the study.

(i) **Communications concerning proposed DER projects.** In the course of processing an application for interconnection and parallel operation and in the conduct of pre-interconnection studies, the customer must provide the company detailed information concerning proposed DER facilities. Communications concerning the nature of proposed DER facilities must be made subject to the requirements of §25.84 of this title (relating to Annual Reporting of Affiliate Transactions for Electric Utilities), §25.272 of this title

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Commented [A19]: TAEBA recommends this language change to reflect the maximum likely residential system size in Texas.

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(relating to Code of Conduct for Electric Utilities and their Affiliates), and §25.273 of this title (relating to Contracts between Electric Utilities and their Competitive Affiliates). A company and its affiliates must not use such knowledge of a proposed DER project submitted to it for interconnection or study to prepare competing proposals to the customer that offer either discounted rates in return for not installing the proposed DER project, or offer a competing DER project.

(j) **Equipment certification.** A DER unit that is certified to be in compliance by an NRTL must be installed on a company's distribution system in accordance with an approved interconnection control and protection scheme without further review of their design by the company.

(k) **Designation of company contact persons for matters relating to DER interconnection.**

(1) Each company must designate a person or persons who will serve as the company's contact for all matters related to DER interconnection.

(2) Each company must identify to the commission its DER contact person.

(3) Each company must provide convenient access through its internet web site to the names, telephone numbers, mailing addresses and electronic mail addresses for its DER contact person.

(l) **Time periods for processing applications for interconnection and parallel operation.** To apply for interconnection the customer must provide the company a completed

application for interconnection and parallel operation. The interconnection of a DER must occur in accordance with the following schedule:

(1) For a DER facility with certified equipment, interconnection must occur within four weeks of the company's receipt of a completed application.

(2) For a DER facility without certified equipment, interconnection must occur within six weeks of the company's receipt of a completed application.

(3) If interconnection of a particular DER facility will require substantial capital upgrades to the company's distribution system, the company must provide the customer an estimate of the schedule and cost attributable to the customer for the upgrade. If the customer desires to proceed with the upgrade, the customer and the company will execute a contract for the completion of the upgrade. The interconnection must occur no later than two weeks following the completion of such upgrades, except in situations in which a customer is not able to connect within two weeks following the completion of such upgrades, this time may be extended by agreement of the company and the customer. The company must employ best reasonable efforts to complete such system upgrades in the shortest time reasonably practical.

(4) A company must use best reasonable efforts to interconnect facilities within the time frames described in this subsection. In the event a company determines that it cannot interconnect a facility within the time frames prescribed by this subsection, the company must notify the applicant in writing. The notification must identify each reason interconnection could not be performed in accordance with the schedule and provide an estimated date for interconnection.

(5) Each application for interconnection and parallel operation must be processed by the company in a non-discriminatory manner. An application must be processed in the order that it is received. In the event an application requires minor modifications while the application is under review by the company, such minor modifications will neither render the application incomplete nor require the application to be treated as a new or separate application.

(m) **Reporting requirements.**

(1) Each company must maintain records concerning applications received for interconnection and parallel operation of DERs. Such records will include:

(A) the name of the applicant;

(B) the business address of the applicant;

(C) the location of the proposed facility by county;

(D) the capacity rating of the facility in kilowatts;

(E) whether the facility is a renewable energy resource as defined in §25.173 of this title (relating to Goal for Renewable Energy);

(F) the date each application is received;

(G) documents generated in the course of processing each application;

(H) correspondence regarding each application; and

(I) the final disposition of each application.

(2) The owner of a DER facility that is interconnected in accordance with this section must report to the company any change in ownership of the facility or the cessation of operations of a facility within 14 days of such change.

(3) By March 30 of each calendar year, every company must file with the commission the form prescribed by subsection (r) of this section . The form must be filed in a format native to Microsoft Excel and must permit basic data manipulation functions, such as copying and pasting of data. report must list:

(A) each new DER facility interconnected with the system since the previous year' report;

(B) any change in ownership or the cessation of operations of any DER that has been reported to the company and not included in the previous report;

(C) the capacity of each facility and whether it is a renewable energy resource;;

(D) the feeder or other point on the company's distribution system where the facility is interconnected; and

(E) all applications for interconnection received during the previous one-year period, and the disposition of such applications.

(n) **Distributed natural gas generation facility.** This section applies only to a DER that is a distributed natural gas generation facility geographically located within the ERCOT power region.

(1) Upon request of an owner or operator of a distributed natural gas generation facility, a company must:

(A) allow the owner or operator to interconnect with and utilize transmission and distribution facilities to transmit electricity to another entity that is acceptable to the owner or operator; and

(B) comply with Chapter 25, Subchapter I, Division 1 §§25.191–25.203 (relating to Open- Access Comparable Transmission Service for Electrical Utilities in the Electric Reliability Council of Texas) of this title, or a tariff approved by the Federal Energy Regulatory Commission (FERC).

(2) In the event that a company seeks to recover an amount in excess of the estimate provided under PURA §35.036(e) by more than 5%, an owner or operator of a distributed natural gas generation facility may petition the commission to address the discrepancy.

(3) This subsection does not require an electric cooperative to transmit electricity to a retail POI in the certificated area of the electric cooperative if the electric cooperative has not adopted customer choice.

(o) **Alternative requirements and standards.** An independent system operator (ISO) may establish interconnection requirements and standards for DERs interconnecting to, and registering with, that ISO in addition to the requirements and standards prescribed under this section.

(p) **DER Interconnection Agreement.** Figure: 16 TAC §25.211(p)

(q) **Application for Interconnection of DERs.** Figure: 16 TAC §25.211(q)

(r) **Annual DER Report.** Figure: 16 TAC §25.211(r)

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§25.212. Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation. (REPEAL)

§25.212. Technical and Operational Requirements for Parallel Operation of Interconnected Distributed Energy Resources (DERs).

(a) **Application.** This section prescribes the minimum technical and operational requirements that must be maintained on an ongoing basis for all distributed energy resources (DERs) in Texas, interconnected and operating in parallel with a Distribution Service Provider's (DSP) distribution system.

(b) **Definitions.** The following words and terms when used in this section have the following meanings, unless the context indicates otherwise:

(1) **Certified equipment** A specific generating and protective equipment system or systems that has been certified by a National Recognized Testing Lab (NRTL) as complying with applicable sections of UL-1741 and IEEE-1547-2018 standards, as determined by the DSP and relating to safety and reliability when paralleling with the grid at the time of interconnection. The Commission will consider updates to the above NRTL standards on a five-year basis.

Commented [A21]: Modification made in accordance with our comments in section §25.210.

(2) **DER** A source of electric power connected at a voltage less than 60 kilovolts (kV).

(3) **DER operator** Any entity operating a DER or seeking to interconnect a DER in Texas.

(4) **Distribution system** – A DSP's electric system operating under 60 kV.

(5) **Interconnection** means the physical connection of a DER to a DSP's distribution system in accordance with the requirements of §25.210 or §25.211, as applicable.

(6) **Legacy DER** – A DER interconnected on or before 90 calendar days from the effective date of this section; or a DER for which a completed interconnection application was received by the DSP prior to 90 calendar days after the effective date of this section. A DER that is registered with ERCOT, or is over one MW and interconnected within the ERCOT region, is not a legacy DER.

(7) **Nationally Recognized Testing Laboratory (NRTL)** An organization recognized by the Occupational Safety and Health Administration (OSHA).

(8) **Parallel operation (includes parallel, paralleling, and operates in parallel)** The operation of a DER while the DER is interconnected to the distribution system.

(9) **Point of interconnection (POI)** – The point where the electrical conductors of the distribution system are interconnected to a DER's conductors and where any transfer of electric power between the DER and the distribution system takes place, such as the switchgear near the meter.

(10) **Protective Function** A function carried out using hardware or software that is designed to respond to unsafe operating conditions before, during, and after the interconnection of a DER. For purposes of this definition, unsafe operating conditions are conditions that, if left uncorrected, would result in harm to personnel, damage to equipment, unacceptable system instability or operation outside legally established parameters affecting the quality of service to other customers connected to the distribution system.

(11) **Stabilized** – A distribution system is considered stabilized when, following a disturbance, the distribution system returns to normal range of voltage and

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frequency for a duration of no less than two minutes, unless a shorter time is specifically permitted by the interconnecting DSP.

(c) **Operational standards and performance requirements for DERs.** A DER, except for a legacy DER, must comply with the requirements of this subsection on an ongoing basis.

(1) **Power quality.**

(A) A DER must not cause the primary and secondary circuit voltage to exceed the nominal operating ranges established in American National Standards Institute, Incorporated (ANSI) C84.1.

(B) A DER must comply with the following power quality requirements.

(i) A DER that qualifies for primary service must not cause step or ramp changes in the root mean squared (RMS) voltage at the point of interconnection exceeding 3% of nominal and exceeding 3% per second averaged over a period of one second.

(ii) A DER that qualifies for secondary service must not cause step or ramp changes in the RMS voltage exceeding 5% of nominal and exceeding 5% per second averaged over a period of one second.

(iii) Flicker must be measured and assessed by methods defined in IEEE 1453-2015 and must be no more than:

E_{Pst}	E_{Plt}
0.35	0.25

(I) E_{Pst} is the emission limit for the short-term flicker severity (P_{st}). If not specified differently, the P_{st} evaluation time is 600 seconds.

(II) E_{Plt} is the emission limit for long-term flicker severity (P_{lt}). If not specified differently, the P_{lt} evaluation time is two hours.

(iv) The following current distortion limits are exclusive of any harmonics present in the DSP's distribution system without the DER connected. Current distortion must be no more than:

Individual odd harmonic order (h)	***h<11***	***11≤h<17***	***17≤h<23***	***23≤h<35***	***35≤h<50***	**Total Rated current distortion (TRD)**
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

Individual even harmonic order	***h=2***	***h=4***	***h=6***	***8≤h<50***
Percent (%)	1.0	2.0	3.0	Range and limits as defined for odd harmonics

(C) For short-circuit faults on the distribution system to which a DER is connected, the DER must cease to energize and trip within ten cycles if the voltage on one or more phases falls below -30% of nominal voltage on the

utility system serving the DER unless specified otherwise by the DSP. This requirement is not applicable to faults that cannot be detected by the DSP's protection systems.

(D) A DER must detect and cease to energize and trip all phases to which the DER is connected for any open-phase condition. The DER must cease to energize and trip within two seconds of the open-phase condition.

(2) **Frequency and voltage.** A DER, except for a legacy DER, must comply with the requirements of this paragraph on an ongoing basis unless the DER is over one MW or registered with ERCOT and alternative requirements have been established in accordance with paragraph (3) of this subsection.

(A) A DER must detect any unintentional island condition and, within two seconds of the formation of the island, must cease to energize and trip. The DER must not remain connected to or energize a de-energized circuit owned by the DSP. When restoring output after momentary cessation, the restore output settings of the DER must be coordinated with the DSP's reclosing timing.

(B) A DER must not connect and operate in parallel with the distribution system unless it is capable of detecting the system voltage and frequency, and synchronizing with the DSP's distribution system, and the applicable system voltage and frequency are within the ranges specified below:

Enter Service Criteria		**System**
Applicable voltage within range	Minimum	0.917 per unit (p.u.)
	Maximum	1.05 p.u.

Frequency within range	Minimum	59.5 Hz
	Maximum	60.1 Hz

Aggregate rating of DER units (kVA)	**Frequency difference (Hz)**	**Voltage difference (p.u.)**	**Phase Angle difference (degrees)**
0-500 kVA	0.3	0.10	20
>500-1500 kVA	0.2	0.05	15
>1500 kVA	0.1	0.03	10

(C) Each DER must have frequency droop parameters set to a maximum of 5% at 0.017 Hz.

(D) Each DER utilizing synchronous generation must have over-voltage and under-voltage set to trip during the following abnormal operating:

Synchronous Must-Trip Settings	**Voltage (V) (p.u. of nominal)**	**Clearing Time (seconds)**
OV2	≥ 1.20	0.16
OV1	≥ 1.10	2
UV1	≤ 0.70	2
UV2	≤ 0.45	0.16

(E) Each DER utilizing synchronous generation must ride through the following abnormal operating conditions:

Voltage (p.u. of nominal)	**Minimum Ride-Through Time (seconds)**
$0.88 \leq V \leq 1.10$	continuous
$0.70 \leq V < 0.88$	Linear slope of 4 seconds/1 p.u. voltage starting at 0.7 seconds at 0.7 p.u.

(F) Each DER utilizing inverter-based generation must have over-voltage and under-voltage relays set to trip during the following abnormal operating conditions:

Inverter Must-Trip Settings	**Voltage (p.u. of nominal)**	**Clearing Time (seconds)**
OV2	≥ 1.20	0.16
OV1	≥ 1.10	13.0
UV1	≤ 0.88	21.0
UV2	≤ 0.50	2.0

(G) Each DER utilizing inverter-based generation must ride-through the following abnormal operating conditions:

Voltage (p.u. of nominal)	**Ride-Through Mode**	**Minimum Ride-Through Time (seconds)**
$1.10 < V \leq 1.20$	Momentary Cessation	12

$0.88 \leq V \leq 1.10$	Continuous Operation	continuous
$0.70 \leq V < 0.88$	Mandatory Operation	20
$0.50 \leq V < 0.70$	Mandatory Operation	10
$V < 0.50$	Momentary Cessation	1

(H) Each DER must have under-frequency and over-frequency relays set to trip during the following abnormal operating conditions:

Must-Trip Function	**Frequency (Hz)**	**Clearing Time (seconds)**
OF2	62.0	0.16
OF1	61.2	300.0
UF1	58.5	300.0
UF2	56.5	0.2

(I) Each DER must ride-through the following abnormal operating conditions:

Frequency (f) (Hz)	**Ride-Through Mode**	**Minimum Ride-through Time (seconds)**
f > 61.8	No ride-through requirements	
$61.2 < f \leq 61.8$	Mandatory Operation	299
$58.8 \leq f \leq 61.2$	Continuous Operation	continuous
$57.0 \leq f < 58.8$	Mandatory Operation	299
f < 57.0	No ride-through requirements	

(J) Each DER must meet the reactive power requirements below and, if capable, must have dynamic voltage support enabled.

Category of DER	Injection capability as percent of nameplate apparent power rating (kVA)	Absorption capability as percent of nameplate apparent power rating (kVA)
A (non-inverter based)	44	25
B (inverter based)	44	44

(K) A DER which parallels with the distribution system for 100 milliseconds or less (high speed closed transition switching), must also have at minimum the following protective devices: an interconnect disconnect device, a generator disconnect device, a breaker failure scheme, and an automatic synchronizing check for a DER with stand-alone capability. The DER provider may be required to provide the DSP test reports that demonstrate that the system operated in less than 100 milliseconds and that breaker failure, hung breaker, and shunt trip protective safety measures were installed and tested. Written comments are to be placed in the test report by the testing agent stating the system operated as designed.

(3) **Alternative frequency and voltage.** DERs with a nameplate capacity of over one MW or that are registered with ERCOT may be subject to alternative frequency and voltage standards than those under paragraph (2) of this subsection.

(A) **ERCOT.**

(i) ERCOT must establish and maintain rules for technical and operational requirements of DERs over one MW and for DERs registered with ERCOT that are interconnected in the ERCOT region. The rules must cover the same subject matter established in paragraph (2) of this subsection.

(ii) DERs located in the ERCOT region that have a nameplate capacity of one MW or more or that are registered with ERCOT must follow requirements established by ERCOT under this paragraph.

(B) **DSPs located outside the ERCOT region.**

(i) A DSP located outside of the ERCOT region may establish and maintain technical and operational requirements that are different, but cover the same subject matter, as those established in paragraph (2) of this subsection but, as applicable, are consistent with the operational requirements established by the DSP's applicable ISO. A DSP that establishes and maintains technical and operational requirements must:

(I) Make the requirements publicly available on the DSP's website;

(II) Provide all interconnected DER operators and DER operators in the process of seeking interconnection a copy of the published DSP's technical and operational requirements; and

(III) Must provide all existing interconnected DER operators that are subject to requirements under this subsection, at a minimum, six months to come into compliance with the new technical and operational requirements.

(ii) If a DSP located outside the ERCOT region establishes alternative requirements, and a DER has a nameplate capacity over one MW, is interconnected to the DSP's distribution system, then the DER is required to comply with the requirements established by a DSP under this paragraph.

(d) **Transition from legacy DER standards.**

(1) Beginning 90 calendar days after the effective date of this section, any equipment or facilities installed on a legacy DER must comply with the standards under subsection (c) of this section.

(2) A legacy DER must transition to the standards under subsection (c) of this section within 150 calendar days from the occurrence of any of the following actions:

(A) A change in the mode of energy production of any one or more of the generators, including equipping a generator to be duel fuel capable if the DER was not previously duel fuel capable.

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(B) The replacement of any generator, inverter, or protective relay.

(C) Any changes to the DER that would result in the DER's nameplate capacity to increase:

(i) by more than 10% of the DER's nameplate capacity at the time this section becomes effective; or

(ii) 100 kW or more.

(3) Within 150 days from the effective date of this section, a DER that is registered with ERCOT, or is over one MW and interconnected within the ERCOT region must transition to or otherwise comply with the standards under subsection (c) of this section.

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(c) **Operational standards and performance requirements for legacy DERs.** A legacy DER must comply with the requirements of this subsection on an ongoing basis

(1) **Voltage.** A DER operator must operate the generating equipment of a legacy DER in such a manner that the voltage levels on a DSP's distribution system are in the same range as if the generating equipment were not connected to a DSP's distribution system. A DER operator must provide an automatic method of disconnecting the legacy DER from a DSP's distribution system if a sustained voltage deviation in excess of ~~5.0~~ % or ~~10~~% from nominal voltage persists for more than 30 seconds, or a deviation in excess of ~~110~~% or ~~30~~% from nominal voltage persists for more than ten cycles. A legacy DER may be reconnected when a DSP's distribution system voltage and frequency return to normal range and are stabilized.

(2) **Flicker.** A legacy DER must not cause excessive voltage flicker on a DSP's distribution system. This flicker must not exceed 3.0% voltage dip, in accordance with IEEE 519 as measured at the point of interconnection.

(3) **Frequency**. The operating frequency of a legacy DER must not deviate more than 10.5 Hz or 0.7 Hz from a 60 Hz base. A legacy DER must automatically disconnect from a DSP's distribution system within 15 cycles if this frequency tolerance cannot be maintained. A legacy DER may be reconnected when a DSP's distribution system voltage and frequency return to normal range and are stabilized.

(4) **Harmonics.** In accordance with IEEE 519 the total harmonic distortion voltage must not exceed 5.0% of the fundamental 60 Hz frequency nor 3.0% of the fundamental frequency for any individual harmonic when measured at the point of interconnection with a DSP's distribution system.

(5) **Fault and line clearing.** A legacy DER must automatically disconnect from a DSP's distribution system within ten cycles if the voltage on one or more phases falls below -30% of nominal voltage on a DSP's distribution system. This disconnect timing also ensures that a legacy DER is disconnected from a DSP's distribution system prior to automatic re-close of breakers. A legacy DER may be reconnected when a DSP's distribution system voltage and frequency return to normal range and stabilized. To enhance reliability and safety and with a DSP's approval, a DER operator may have installed a modified relay scheme with delayed tripping or blocking using communications equipment between the legacy DER and the DSP.

(6) **Requirements specific to a DER paralleling for sixty cycles or less (closed transition switching).** A legacy DER that operates in parallel with the distribution system for 60 cycles are less must have the following protective devices:

(A) an interconnect disconnect device;

(B) a generator disconnect device;

(C) as applicable, an automatic synchronizing check for generators with stand-alone capability;

(D) an over-voltage trip;

(E) an under-voltage trip;

(F) an over-frequency and under-frequency trip; and

(G) as required by the DSP, either of the following:

(i) a ground over-voltage trip; or

(ii) a ground over-current trip depending on the grounding system.

(f) **General interconnection and protection requirements for DERs.**

(1) A DER must meet all applicable national, state, and local construction and safety codes and regulations.

(2) A DER must be equipped with the necessary hardware and software equipment designed to prevent the DER from:

(A) Connecting to a DSP's de-energized circuit, and

(B) Connecting or paralleling with the DSP's distribution system unless the DSP's distribution system service voltage and frequency are stabilized.

(3) The design of certified equipment may be reviewed and approved by the DSP.

(4) If the DER is using certified equipment when interconnecting with the DSP's distribution system, the DER must:

(A) Utilize the protective settings and operations specified by the DSP; and

(B) Interconnect in accordance with an approved interconnection control and protection scheme.

(5) If a synchronous DER's equipment is not certified equipment, the DER must demonstrate compliance with IEEE1547-2018 standards during the testing for startup and commissioning.

(6) A DER operator is responsible for protecting its DER in such a manner that DSP's distribution system outages, short circuits, or other disturbances including zero sequence currents and ferroresonant over-voltages do not damage the DER. The DER's protective equipment must also prevent unnecessary tripping of the DSP's distribution system breakers that would affect the DSP's capability of providing reliable service to other customers.

(7) For a DER that has a nameplate capacity greater than two MW, the DSP may require that a communication channel be provided by the DER operator to provide communication between the DSP and the DER.

(8) Circuit breakers, reclosers, or other interrupting devices at the point of interconnection must be capable of interrupting the maximum available fault current. A DER that has a nameplate capacity greater than two MW and exporting energy to the DSP's distribution system must have a redundant circuit breaker unless a device suitable for the rated application is used and is capable of interrupting current to the distribution resource.

(9) A DER operator will install a manual disconnect device as part of the DER that has a visual break that is appropriate to the voltage level (a disconnect switch, a draw-out breaker, or fuse block), that is accessible to the DSP's personnel, and is capable of being locked in the open position. The DER must follow the DSP's switching, clearance, tagging, and locking procedures, which the DSP must provide to the DER operator.

(g) **Control, protection, and safety equipment requirements for all DERs.** A DSP may require a DER operator to install additional operational or protection devices on a DER exporting energy to a DSP's distribution system and may require the DER operator to coordinate with the DSP for such operations.

(1) **Single-phase generators connected to a DSP's distribution system.** The necessary control, protection, and safety equipment specific to a single-phase generator that has a nameplate capacity of 50 kW or less connected to a secondary or primary system includes an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over-frequency and under-frequency trip, and a synchronizing check for synchronous and other types of generators with stand-alone capability.

(2) **Three-phase synchronous generators, induction generators, and inverter systems.**

(A) **Three-phase synchronous generators.** DER circuit breakers must be three-phase devices with electronic or electromechanical control. A DER

operator is solely responsible for properly synchronizing its DER with a DSP's distribution systems.

(i) The excitation system response ratio must not be less than 0.5. A DER's excitation systems must conform, as near as is reasonably achievable, to the field voltage versus time criteria specified in the most recent version of IEEE C50.13 to permit adequate field forcing during transient conditions.

(ii) For a DER that has a nameplate capacity greater than two MW the DER operator must at all times maintain the automatic voltage regulator (AVR) for each generating unit in service and operable. If the AVR is removed from service for maintenance or repair, the DSP may require that the DSP dispatching office be notified, and the DER must be removed from service until the AVR is returned to service. The DSP must be notified regarding both the removal and return to service of the AVR.

(B) **Three-phase induction generators and inverter systems.** A DER utilizing induction generation may be interconnected and brought up to synchronous speed (as an induction motor) if the DER operator can demonstrate that the initial voltage drop measured on the DER side of the POI is within the visible flicker stated in subparagraph (e)(1)(B)(iii) of this section or paragraph (e)(2) of this section for legacy DERs, as applicable. If the DER operator cannot demonstrate that the initial voltage drop measured on the distribution system is within the visible flicker

requirement, then the DER operator may be required to install hardware or employ other techniques to bring voltage fluctuations to acceptable levels.

(i) Line-commutated inverters do not require synchronizing equipment.

(ii) Self-commutated inverters, whether of a DSP interactive type or stand-alone type, must be used in parallel with a DSP's distribution system only with synchronizing equipment.

(iii) Direct-current generation must not be operated in parallel with the DSP's distribution system.

(C) **Protective function requirements.** The protective function requirements for three-phase facilities of different sizes and technologies are listed below.

(i) A DER that has a nameplate capacity of ten kW or less must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over-frequency and under-frequency trip, and for facilities with stand-alone capability a manual or automatic synchronizing check.

(ii) A DER that has a nameplate capacity in excess of ten kW but not more than 500 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over-frequency and under-frequency trip, for facilities with stand-alone capability a manual or automatic synchronizing check, either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the DSP, and reverse power sensing if the DER is not exporting energy.

Communication based telemetry and transfer trip may also be required by the DSP as part of a transfer tripping or blocking protective scheme.

(iii) A DER that has a nameplate capacity of more than 500 kW but not more than 2,000 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over-frequency and under-frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the DSP, an automatic synchronizing check for facilities with stand-alone capability, and reverse power sensing if the DER is not exporting energy. If the DER is exporting energy, the power direction protective function may be used to block or delay the under-frequency trip if the DSP agrees in writing to such use. Communication based telemetry and transfer trip may also be required by the company as part of a transfer tripping or blocking protective scheme.

(iv) A DER that has a nameplate capacity of more than two MW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over-frequency and under-frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the DSP, reverse power sensing if the DER is not exporting energy and, for facilities with stand-alone capability, an

automatic synchronizing check and AVR for facilities. If the DER is exporting energy, the power direction protective function may be used to block or delay the under-frequency trip if the DSP agrees in writing to such use. A DSP may also require communication-based telemetry and transfer trip by the company as part of a transfer tripper or blocking protective scheme.

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(h) **Maintenance**. A DER operator is responsible for routine maintenance of the DER and for maintaining control, protection, and safety equipment.

(1) A DER operator must use good utility practice to maintain each DER and associated interconnection facilities under its ownership or control to reduce the likelihood of adverse impacts on other customers or the distribution system.

(2) A DER operator must maintain records of such maintenance activities, which the DSP may review at reasonable times.

(3) For a DER that has a nameplate capacity greater than 500 kW, the DER operator must keep a log of the DER operations.

(i) At a minimum, the log must include the date, DER time on, DER time off, and MW and megavar output.

(ii) The DSP may review such logs at least once every 30 calendar days.