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PROJECT NO. 54233

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

INITIAL COMMENTS OF AEP TEXAS INC.

AEP Texas Inc. respectfully provides the following comments on the discussion draft provided by the staff of the Public Utility Commission of Texas ("Commission Staff") that would (1) repeal existing 16 Texas Administrative Code ("TAC") § 25.211, relating to Interconnection of Distribution Resources for Parallel Operation; (2) propose new § 25.211, relating to Interconnection of Distribution Resources for Parallel Operation; (3) repeal existing § 25.212, relating to Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation; and (4) propose new 16 TAC § 25.212 relating to Technical and Operational Requirements for Parallel Operation of Interconnected Distribution Resources. As requested, a standalone executive summary is the last page of this filing. AEP Texas appreciates the work of the Commission and the opportunity to submit comments on the issues presented by this project.

I. Background

Commission Rules 25.211 and 25.212 were initially passed in 1999. Implementation of the rules was intended to promote the use of distributed resources during periods of capacity constraints, enhance the reliability of electric service and economic efficiency in the production and consumption of electricity, and provide customers greater opportunities to control the price and quality of electricity within their facilities.[1] Over the past 23 years, Rule 25.211 has been amended four times, and Rule 25.212 has not been amended. Around the time these rules were passed, the vast majority of distributed generation units installed in the United States were customer owned and operated and were used primarily to supply energy services to their owners.

[1] *Rules for Interconnection of Distributed Generation*, Project No. 21220, Order Adopting New § 25.211 and § 25.212 as Approved at the November 18, 1999 Open Meeting and Published in the Texas Register on December 17, 1999 at 1 – 2 (Dec. 1, 1999).

Since then, distributed energy resource ("DER") penetration levels have increased, technologies have advanced, and DERs are increasingly seeking to supply energy to the grid. Accordingly, AEP Texas agrees with the Commission that it is time to analyze the current issues and update 16 TAC §§ 25.211 and 25.212 accordingly.

II. Comments

AEP Texas appreciates the work that the Commission has engaged in related to DERs and in developing the proposed discussion draft. In lieu of providing specific comments on the discussion draft, however, AEP Texas notes that its subject matter experts along with the subject matter experts of other utilities also have engaged in significant work discussing and analyzing issues related to interconnection of DERs, including technical and operational requirements. Out of that work, AEP Texas is submitting its working draft of proposed language for updated 16 TAC § 25.211 and § 25.212 for the Commission's consideration, which include:

- AEP Texas Working Draft Proposed § 25.211, along with proposed Figure § 25.211(h); and
- AEP Texas Working Draft Proposed § 25.212, along with proposed Figure § 25.212(c).[2]

AEP Texas emphasizes that the attached documents are working drafts and should not be interpreted as the final position of AEP Texas. AEP Texas is offering these for discussion purposes because, although not final, they are conceptually different enough from what has been presented that further discussion among the stakeholders is warranted before proceeding with a proposal for publication.

In addition to the attached working drafts, AEP Texas acknowledges the substantial collaboration in 2022 between the ERCOT transmission and distribution utilities and several energy storage developers to address issues specific to the interconnection of distribution energy storage resources ("DESRs"). In Project No. 51603, Hunt Energy Network submitted a letter that included a "(i) draft standard DESR interconnection agreement (Attachment 1); (ii) a process and timeline for the interconnection of DESRs (Attachment 2); and (iii) a draft strawman rule

[2] The attached working draft proposals do not include a draft application or draft agreement.

addressing the interconnection process and cost treatment of DESRs (Attachment 3)."[3] While the Staff's discussion draft may have relied upon one or more of the documents in that filing, AEP Texas believes stakeholders will benefit from further discussion as outlined in these comments.

The attached proposed revisions to 25.211 and 25.212 represent the interconnection and operation requirements necessary for the reliable operation of utilities' transmission and distribution systems as pertains to all DERs. The primary purpose of current 16 TAC § 25.211 is to establish the terms and conditions that govern the interconnection and parallel operation of both on-site distributed generation and natural gas distributed generation under provisions of the Public Utility Regulatory Act.[4] The purpose of current 16 TAC § 25.212 is to describe the requirements and procedures for safe and effective connection and operation of distributed generation. As the Commission noted when Project No. 51603 was initiated, those sections should be updated to reflect more current industry standards, such as IEEE 1547-2018. The attached drafts reflect updated and modernized revisions to those sections that reflect technical interconnection and operational requirements for all DERs to reasonably assure reliable operation of utility transmission and distribution systems. In contrast, the discussion draft of the rule appears to be geared toward larger distributed energy resource applications generally, and DESRs in particular. The discussion draft also appears to embed some market and cost recovery issues, which should more appropriately be addressed in Project No. 54224, *Cost Recovery for Service to Distributed Energy Resources (DERs)* and/or a new, separate rule designed specifically to cover those types of issues. Other important differences between the drafts also deserve further discussion among interested stakeholders.

Given the significant effect that DERs will have on utility systems and operations, and because there are significant differences between the discussion draft and the attached working drafts, AEP Texas urges the Commission not to proceed with a proposal for publication at this time. Instead, AEP Texas respectfully requests that the Commission facilitate one or more technical conferences to discuss and analyze the various ideas put forward in the discussion draft and in comments received on the discussion draft. Such technical conferences will help develop

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[3] *Review of Distributed Energy Resources*, Project No. 51603, Hunt Energy Network, L.L.C. Letter to Commissioners at 1 (Oct. 5, 2022).

[4] Tex. Util. Code §§ 11.001 – 66.016 ("PURA").

a revised framework for these two rules that better represents the perspectives of the various stakeholders in this process.

III. Conclusion

AEP Texas appreciates the Commission's consideration of these initial comments and looks forward to participating in future discussions with interested stakeholders on these issues.

Respectfully submitted,

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ON BEHALF OF AEP TEXAS INC.

PROJECT NO. 54233

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

EXECUTIVE SUMMARY OF INITIAL COMMENTS OF AEP TEXAS INC.

AEP Texas appreciates the work of the Commission on the proposed repeal and replacement of 16 Texas Administrative Code §§ 25.211 and 25.212. An executive summary of AEP Texas' comments is below.

- AEP Texas has provided as part of its initial comments its working version of proposed draft rules that are based on significant time and effort among utility subject matter experts discussing and analyzing interconnection issues.
- There are significant differences between the working version that AEP Texas has provided and the discussion draft that warrant further discussion before proceeding with a proposal for publication. AEP Texas respectfully requests that the Commission facilitate one or more technical conferences to assist in developing a revised framework for these two rules that better represents the perspectives of the various stakeholders in this process.

CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS.

Subchapter I. TRANMISSION AND DISTRIBUTION.

DIVISION 2. TRANSMISSION AND DISTRIBUTION APPLICABLE TO ALL ELECTRIC UTILITIES.

§25.211. General Requirements for Interconnection and Parallel Operation of Distributed Energy Resources (DER).

Application. This section and §25.212 of this title (relating to Technical Requirements for Interconnection and Parallel Operation of Distributed Energy Resources) apply to the interconnection and parallel operation of customer's DER facilities with maximum aggregated capacity ratings at a single point of common coupling as shown in Table AMR to an electric utility's distribution system for all purposes except to the extent preempted by federal law or, for non-ERCOT utilities, when inconsistent with the rules, policies, procedures, or other binding determinations of the Federal Energy Regulatory Commission or a Regional Transmission Organization or Independent System Operator with jurisdiction or authority over the utility.

Table AMR – Aggregate Maximum Ratings *Dependent on Pre-Interconnection Study	
Voltage Class	Capacity Rating
Up to 5 kV	Less than 0.5 MVA*
5 kV up to and including 15 kV	10 MVA or less*
Above 15 kV	Up to but less than 20 MVA*

(a) **Purpose.** The purpose of this section includes stating the terms and conditions that govern the interconnection and parallel operation of DER facilities in order to implement Public Utility Regulatory Act (PURA) §39.101(b)(3) and PURA §35.036, as applicable to each PURA. Sales of power by DER facilities and distributed natural gas generation facilities in the intrastate wholesale market are subject to §§25.191-25.203 of this title (relating to Open-Access Comparable Transmission Service for Electrical Utilities in the Electric Reliability Council of Texas).

(b) **Definitions.** The following words and terms when used in this section and §25.212 of this title shall have the following meanings, unless the context indicates otherwise:

(1) **Application** -- The form Application for DER Interconnection and Parallel Operation prescribed in subsection (l) of this section.

(2) **Capacity** – The apparent power nameplate capacity of a facility or, if the output has been limited by the manufacturer or by operating controls, settings, or supplemental devices which limit the facility's kVA capabilities or

connected capacity, the limited output capacity, whichever is less upon mutual agreement with the distribution utility.

(3) **Certified Customer Equipment** -- A specific generating and protective customer equipment system or systems that have been certified by a Nationally Recognized Testing Lab (NRTL) as complying with applicable portions of UL-1741 and IEEE-1547 standards as determined by the distribution utility relating to safety and reliability when paralleling with the utility grid at the time of interconnection.

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

(5) **Customer** -- The entity who is responsible for the purchase, installation and operation of the DER facility that is interconnected and operated in parallel with a distribution system.

(6) **Distributed energy resource (DER) (or distributed energy resource (DER) facility) --** A source of electric power that is located at a customer's point of delivery (point of common coupling) with maximum aggregated capacity ratings as shown in Table AMR, connected at a voltage of less than 60 kilovolts (kV) which may be connected in parallel operation to the utility's distribution system and not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting as shown in Table AMR to a utility and subject to utility's Duty to Interconnect. Demand Response, DESR, and other DERs participating in energy or ancillary service markets may also be addressed in other Commission or RTO rules. This term includes a distributed natural gas generation facility as defined in PURA § 31.002 and a distributed renewable generation facility as defined in § 25.217 of this title.

(7) **Distribution system** -- The electric power delivery system owned by an electric utility and operated below 60 kV.

(8) **Interconnection or interconnected**—The term used to reference the point of connection at the PCC of the distributed energy resource facility to the distribution system in accordance with the requirements of this section so that parallel operation can occur.

(9) **Interconnection agreement** -- The form of Agreement for DER Interconnection and Parallel Operation prescribed in subsection (k) of this section.

(10) **DER protective function** -- A function carried out using hardware and software that is designed to prevent unsafe operating conditions from occurring 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.

(11) **Network** -- Consists of two or more utility primary distribution feeder sources electrically tied together on the secondary (or low voltage) side to form one power source for one or more customers. It is designed to maintain service to the customers even after the loss of one of these primary distribution feeder sources.

(12) **Parallel operation** -- The operation of distributed energy resources for any length of time while interconnected to the distribution system.

(13) **Point of common coupling (PCC) or Point of Interconnection (POI)**-- The service point where the electrical conductors of the distribution system are interconnected to the electrical conductors of the customer's DER facility and where any transfer of electric power between the customer equipment and the distribution system takes place, such as switchgear near the meter (typically regarded as the "Utility meter point").

(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 utility system. Pre-interconnection studies may include, but are not limited to, service studies, coordination studies and distribution system impact studies.

(15) **Stabilized** -- A company utility system is considered stabilized when, following a disturbance, the system returns to the normal range of voltage and frequency for a duration of no less than two minutes. A shorter time may be mutually agreed to by the company and customer.

(16) **Substantial modification** – For a given distributed energy resource, a change in the fuel type of any one or more of the energy resources at the facility, the replacement of any inverter or protective relay, or an increase in the facility's capacity (VA output) by more than 10%.

(c) **Duty to Interconnect.** An electric utility shall interconnect its distribution system to DER facilities pursuant to this section and § 25.212, provided that any customer request for interconnection of one or more electric generating and/or energy storage facilities with an aggregate rating not above the values referenced within Table-AMR behind a single point of common coupling, and the terms and conditions for any such interconnection shall be in the electric utility's discretion in accordance with good utility practice. A customer requesting interconnection must submit an application and deliver to the electric utility an interconnection agreement executed by the customer before an interconnection will be established.

(d) **Terms of Service.**

(1) **Application Fee.** A fee will be assessed when submitting an application for paralleling distributed energy resource facilities in accordance with a fee schedule seen in Table AFS-1 below.

Table AFS-1 Application Fee Schedule	
Size	**Cost**
Up to 10 kVA	$50
10 kVA up to and including 500 kVA	$100
Greater than 500 kVA	$500

(2) **Distribution line charge.** Distribution line charges may be assessed to a customer for exporting energy from a DER facility to the utility distribution system.

(3) **Interconnection operations and maintenance costs.** Charges for operation and maintenance of a utility system's facilities may be assessed against a customer for exporting energy to the utility distribution system.

(4) **Testing, Inspection, and Verification costs.** A utility may assess charges when events are repeated or scheduled multiple times for activities involving customer driven requests for testing, inspection, and verification of interconnected equipment or facilities.

(5) **Transmission charges.** Transmission charges may be assessed to a customer for exporting energy from a DER facility to the system. For purposes of this paragraph, the term transmission charges means transmission access and line charges, transformation charges, and transmission line loss charges.

(6) **New or amended interconnection agreements.** A new or amended interconnection agreement entered into 30 or more days after the commission's approval of an electric utility's compliance tariff filed pursuant to paragraph (7) of this subsection shall meet the requirements of this section.

(7) **Tariffs.** Not later than 30 days after the effective date of this amended section, an electric utility shall file with the commission for approval tariff amendments to comply with this amended section, including subsections (k) and (l) of this section. An electric utility shall include in its tariff the fees for interconnection studies. An electric utility that sells electricity shall also include back-up, supplemental, and maintenance power services for distributed generation in its tariff.

(e) **Disconnection and reconnection.** A utility may disconnect a distributed energy resource facility 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 electric utility and customer. Upon expiration or termination of the interconnection agreement with a customer, in accordance with the terms of the agreement, the utility may disconnect customer's facilities.

(2) **Non-compliance with the technical requirements specified in §25.212 of this title.** A utility may disconnect a distributed energy resource facility if the facility is not in compliance with the technical requirements specified in §25.212 of this title. Within two business days from the time the customer notifies the utility that the facility has been restored to compliance with the technical requirements of §25.212 of this title, the utility shall have an inspector verify such compliance. Upon such verification, the customer in coordination with the utility may reconnect the facility.

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

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

(5) **Operating a DER facility prior to receiving a permission to operate from the electric utility.** The utility may disconnect the customer's facility if the electric utility has not issued a permission to operate to the customer prior to the commencement of the DER facility's operation.

(f) **Incremental demand charges**. During the term of an interconnection agreement a utility may require that a customer disconnect its distributed energy resource facility and/or take it off-line as a result of distribution system conditions described in subsection (e)(3) and (4) of this section. Incremental demand charges arising from disconnecting the distributed energy resources as directed by company during such periods shall not be assessed by company to the customer.

(g) **Pre-interconnection studies and time periods for processing applications.**
<u>Figure 16 TAC 25.211(h)</u>

(h) **Designation of utility contact persons for matters relating to DER facility interconnections.**

(1) Each electric utility shall designate a person or persons who will serve as the utility's contact for all matters related to DER facility interconnection.
(2) Each electric utility shall identify to the commission its DER facility contact person.
(3) Each electric utility shall provide convenient access through its internet web site to the names, telephone numbers, mailing addresses and electronic mail addresses for its DER facility contact person.

(i) **Reporting requirements.** Each electric utility shall maintain records of all applications received. Such records will include the name of the applicant, the business address of the applicant, and the location of the proposed DER facility by county, the capacity rating of the proposed DER facility in kilovolt-amperes (kVA), whether the DER facility is a generation facility or an energy storage facility, and if a generation facility, whether it is a renewable energy resource as defined in §25.173 of this title (relating to Goal for Renewable Energy), the date each completed application is received, documents generated in the course of processing each application, correspondence regarding each application, and the final disposition of each application. The owner of a DER facility that is interconnected under this section shall report to the utility any change in ownership of the facility and the cessation of operations of a facility within 14 days of such change. By February 28 of each year, every electric utility shall file with the commission a DER facility interconnection report for the preceding calendar year that identifies each DER facility interconnected with the utility's distribution system. The report shall list the new DER facilities interconnected with the system since the previous year' report, any change in ownership or the cessation of operations of any distributed generation that has been reported to the electric utility and not included in the previous report, the capacity of each facility and whether it is a renewable energy resource, and the feeder or other point on the company's distribution system where the facility is connected. The annual report shall also identify all applications for interconnection received during the previous one-year period, and the disposition of such applications.

(j) **Distributed natural gas generation facility**. This subsection, as well as the other subsections of this section, apply to a distributed natural gas generation facility as defined in PURA § 31.002. This subsection does not require an electric cooperative to transmit electricity to a retail point of delivery in the certificated area of the electric cooperative if the electric cooperative has not adopted customer choice. If there is a conflict between this subsection and another subsection of this section, this subsection controls.

(1) **Transmission**.

(A) **Electric utilities**. At the request of the owner or operator of a distributed natural gas generation facility, an electric utility shall allow the owner or operator of the facility to interconnect with and use transmission and distribution facilities to transmit electricity to another entity that is acceptable to the owner or operator in accordance with this section and the commission's rules for open-access comparable transmission service for electric utilities in ERCOT, §§25.191 - 25.203 of this title, or a tariff approved by the Federal Energy Regulatory Commission (FERC).

(B) **Electric cooperatives**. At the request of the owner or operator of a distributed natural gas generation facility, an electric cooperative shall allow the owner or operator of the facility to use transmission and distribution facilities to transmit the electric power to another entity that is acceptable to the owner or operator in accordance with the commission's rules for open-access comparable transmission service for electric utilities in ERCOT, §§25.191 - 25.203 of this title, or a tariff approved by FERC.

(2) **Interconnection Disputes**. If an electric utility or electric cooperative seeks to recover from the owner or operator of a distributed natural gas generation facility an amount that exceeds the amount in the estimate provided under PURA §35.036(e) by more than 5%, the commission shall resolve the dispute at the request of the owner or operator of the facility.

(k) **Agreement for DER Interconnection and Parallel Operation.** <u>Figure: 16 TAC §25.211(m)</u>

(l) **Application for DER Interconnection and Parallel Operation**. Figure: 16 TAC §25.211(n)

FIGURE 25.211(h)
PRE-INTERCONNECTION STUDIES AND TIME PERIODS FOR PROCESSING APPLICATIONS

(a) **Communications concerning proposed DER facility projects.** In the course of processing applications and conducting pre-interconnection studies, customers shall provide the utility detailed information concerning proposed DER facilities. Such communications shall be subject to the terms of §25.84 of this title (relating to Annual 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). A utility and its affiliates shall not use such knowledge of proposed distributed energy resource projects 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 distributed energy resources or offer competing DER projects.

(b) **Pre-interconnection studies for non-network interconnection of distributed energy resources.** A utility may, in good utility practice, conduct service studies, coordination studies, stability studies, transient studies, and distribution system impact studies. In instances where such studies are deemed necessary, the scope of such studies shall be based on the characteristics of the distributed energy resource facility to be interconnected and the characteristics of the delivery system at the specific proposed point of common coupling. These studies will be based on the aggregate DER facilities attached to the feeder where the customer's DER facility is proposing to connect. A utility shall prepare written reports of the study findings and make them available to the customer. The customer shall receive an estimated cost and timeline for construction of the changes required on the system to facilitate the interconnection. Full funding of the utility determined cost is required to proceed to interconnection. At the Company's discretion, a qualified third party may be contracted to conduct Pre-interconnection studies. The studies shall consider both the costs incurred and the benefits realized as a result of the interconnection of DER to the utility's system.

(1) **Non-network interconnection of distributed energy resource facilities for which no pre-interconnection study fees may be charged.** A utility may not charge a customer a fee to conduct a pre-interconnection study for certified customer equipment used in a non-network interconnection of one or more DER facilities with a combined nameplate or self-limit value of up to 500 kVA that exports not more than 15% of the total minimum load on a single radial feeder and contributes not more than 10% of the maximum potential short circuit current on a single radial feeder.

(2) **Non-network interconnection of distributed energy resource facilities for which pre-interconnection study fees may be charged.** Prior to the non-network interconnection of one or more

distributed energy resource facilities with a combined nameplate rating or self-limit value not to exceed values referenced within Table AMR of 25.211 and not otherwise described in paragraph (1) of this subsection, a utility may charge a customer a fee to offset costs incurred in the conduct of a pre-interconnection study. In those instances where a utility conducts a pre-interconnection study, the time periods in table NN-1 shall apply. If a DER facility request is greater than values referenced within Table AMR of 25.211, the utility may agree to perform Pre-interconnection studies and define the time periods necessary and costs to perform those studies. Upon completion, the utility will coordinate a scoping meeting to discuss the results of the Pre-interconnection studies and requirements/timelines/costs to proceed with interconnection.

Table NN-1
Non-Network Pre-interconnection studies and time periods for processing applications

* Time periods represent the time from utility's receipt of a fully completed application and study fee. Construction times are not included in these estimates.
** If non-certified equipment is used, pre-interconnection studies may require longer timeframes.
***Capacity is considered aggregate nameplate in VA or, if within good utility practice and agreed to by distribution utility and installer, the self-limit value.
****RTO/ISO requirements may extend the time periods for studies to be completed.

Capacity Size ***	Time Period****
Up to and including 500 kVA	4 weeks**
Greater than 500 kVA up to and including 1 MVA	Up to 6 weeks**
Greater than 1 MVA up to and including 2 MVA	Up to 9 weeks**
Greater than 2 MVA and less than 20 MVA	Up to 15 weeks **

(c) **Network interconnection of distributed energy resources.** Certain aspects of secondary grid and spot network systems may create impacts that make network interconnection more costly to implement or negatively affect the reliability. In instances where customers request network interconnection to a secondary grid and spot network system, the utility and the customer shall use reasonable efforts to complete the interconnection and the utility shall utilize the following guidelines:

(1) A utility shall make all reasonable efforts to safely and reliably interconnect all types of network interconnection requests. In certain situations, this may include switching service to a radial feed if practical and if acceptable to customer. A utility may reject applications for a network interconnection of a DER facility if the utility can demonstrate specific reliability or safety reasons why the DER facility should not be interconnected at the requested site. In these cases, the utility shall work with the customer to attempt to resolve such problems and reach a solution to ensure a safe and reliable interconnection.

(2) A utility may approve applications for secondary grid or spot network interconnection of DER facilities that use inverter based protective functions unless the total DER generation, including the new DER facility, on affected feeders represents more than 25% of the total minimum load of the customer facility under consideration.

(3) A utility may postpone processing an application for a grid or spot network interconnection of an individual DER facility under this section if the total existing DER on the targeted feeder represents more than 25% of the total minimum load of the customer facility under consideration. If that is the case, the utility should 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 should be completed according the Table N-1 shown below.

(4) Applications utilizing power flow during automatic transfer schemes where load is transferred between the utility and the DER facility and returning from DER facility to utility in a make before break operation, shall have positive flow of energy from utility to load. These types of application requests are subject to approval, coordination and any commissioning process approvals as required by the utility.

(5) Unless agreed to otherwise with the utility, DER facilities on secondary grid or spot networks shall have provisions to:

(A) Monitor instantaneous power flow at the point of common coupling (PCC) of the DER facility interconnected to the secondary grid or spot network

(B) Provide reverse power relaying and minimum import relaying with capabilities for dynamically controlled inverter functions and similar applications to prevent reverse power flow through network protectors

(C) Provide for the capability to maintain a minimum import level at the PCC as determined by the utility.

(D) Provide capability to control DER facility operation or disconnection of the DER facility from the utility based on an autonomous setting at the PCC and/or a signal sent by the utility.

(6) DER facilities on grid or spot networks shall not:

(A) Cause any network protector (NP) to exceed its loading or fault-interrupting capability.

(B) Cause any NP to separate dynamic sources.

(C) Cause any NP to connect two dynamic systems together.

(D) Cause any NP to operate more frequently than prior to DER facility installation and operation.

(E) Prevent or delay the NP from opening for faults on the utility's network grid.

(F) Delay or prevent NP closure.

(G) Energize any portion of a utility network grid when the utility network grid is de-energized.

(H) Require the NP settings to be adjusted except by consent of the utility.

(I) Prevent reclosing of any network protectors installed on the network. This coordination shall be accomplished without requiring any changes to prevailing network protector clearing time practices of the utility.

(7) In addition to the above requirements, connection of the DER facility to the distribution system is only permitted if the distribution system bus is already energized by more than 50% of the installed NP's.

(d) **Pre-interconnection studies for network interconnections.** Prior to charging a pre-interconnection study fee for a network interconnection of a DER facility, a utility shall first advise the customer of the potential problems associated with interconnection of DER facilities with its network system. For potential interconnections to network systems there shall be no pre-interconnection study fee assessed for a DER facility with inverter systems with an aggregate nameplate capacity not exceeding 20 kVA. For all other facilities the utility may charge the customer a fee to offset its costs incurred in the conduct of the pre-interconnection study. In those instances where a utility conducts an interconnection study, the following shall apply:

(1) The conduct of such pre-interconnection studies shall take no longer than the time periods shown in Table N-1.

(2) A utility shall prepare written reports of the study findings and make them available to the customer.

(3) The studies shall consider both the costs incurred and the benefits realized as a result of the interconnection of a DER facility to the utility's system.

(4) The customer shall receive an estimate of the study cost before the utility initiates the study.

Table N-1 **Network Pre-interconnection studies and time periods for processing applications** * Time periods represent the time from utility's receipt of a fully completed application and study fee. Construction times are not included in these estimates. ** If non-certified equipment is used, pre-interconnection studies may require longer timeframes. ***Capacity is considered aggregate nameplate in VA or, if within good utility practice and agreed to by distribution utility, the self-limit value. ****RTO/ISO requirements may extend the time periods for studies to be completed.	
Capacity Size***	Time Period****
Up to and including 500 kVA	8 weeks **
Greater than 500 kVA up to and including 1 MVA	Up to 10 weeks **
Greater than 1 MVA up to and including 2 MVA	Up to 12 weeks**
Greater than 2 MVA and less than 20 MVA	Up to 20 weeks **

(e) **Processing and time periods for completing the interconnection**

A utility shall use reasonable efforts to process applications and interconnect DER facilities after pre-interconnection studies within the time frames described in this subsection. If in a particular instance, a utility determines that it cannot process and interconnect a facility within the time frames stated in this subsection, the utility will notify the applicant in writing of that fact. The notification will identify the reason or reasons interconnection could not be performed in accordance with the schedule and provide an estimated date for interconnection.

After completion of Pre-interconnection studies, all necessary upgrades shall begin after receipt of funding and invoicing and the securing of appropriate utility agreement. The agreement consists of an estimate of the cost along with a discussion of the timeframe for completion of the required upgrades to the system. Customers delaying decisions to proceed to interconnection after pre-interconnection studies may experience delays in completing their interconnection or possible changes in their pre-interconnection study. Customers not proceeding with interconnections after delays over 90 days may be subject to another pre-interconnection study (with applicable study fee).

All applications shall be processed by the utility in a non-discriminatory manner. Applications shall be processed in the order that they are received. It is recognized that certain applications may require minor modifications while they are being reviewed by the utility. Such minor modifications to a pending application shall not require that it be considered incomplete and treated as a new or separate application.

Table P -1 **Utility Processing Time Periods for Completing the Interconnection** *Scoping meeting to take place within 3 weeks of completion of Pre-interconnection study to discuss results of Pre-interconnection study and requirements/timelines/costs to complete the interconnection **For locations that do not require Pre-interconnection study, subject to 10 kVA processing timeframe	
DER Nameplate Capacity Size or Self Limit Value	**Processing Time Period**
10 kVA or less	Up to 6 weeks
Greater than 10 kVA and less than 20 MVA**	Subject to scoping meeting*

(1) If interconnection of a particular DER facility requires capital upgrades to the system, the utility shall provide the customer with an estimate agreement including the estimate of the required upgrades and the construction schedule for the upgrades. If the customer desires to proceed with the upgrades, the customer and the company will enter into this agreement for the completion of the upgrade.

(2) If the DER facility is a distributed natural gas generation facility as defined in PURA § 31.002 (4-a), then the subsection above of this section also applies with respect to the cost of utility capital upgrades for the interconnection.

CHAPTER	**SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS**
Subchapter I.	**Transmission and Distribution.** **TRANSMISSION AND DISTRIBUTION APPLICABLE TO ALL ELECTRIC UTILITIES.**

§25.212. Technical Requirements for Interconnection and Parallel Operation of Distributed Energy Resources.

(a) **Purpose.** The purpose of this section is to describe the technical requirements and procedures for safe and effective connection and operation of DER facilities to the distribution system.

(1) A customer may operate 60 Hertz (Hz), three-phase or single-phase DER facility, whether a qualifying facility (QF) or a non-QF, in parallel with the distribution system pursuant to an interconnection agreement, provided that the customer equipment meets or exceeds the requirements of this section.

(2) This section describes typical interconnection requirements. Certain specific interconnection locations and conditions may require the installation and use of more sophisticated protective and telemetry devices and operating schemes, especially when the DER facility is exporting power to the distribution system.

(3) If the utility concludes that an application describes DER facilities that may require additional protective and telemetry devices and operating schemes, the utility shall make those additional requirements known to the customer at the time the pre-interconnection studies are completed.

(4) Where the application of the technical requirements set forth in this section appears inappropriate for a specific DER facility, the customer and utility may agree to different requirements, or a party may petition the commission for a good cause exception after making every reasonable effort to resolve all issues between the parties.

(5) When a 1000 kVA or greater DER facility is rendered offline for maintenance or repair for greater than 24 hours, the distribution utility shall be notified immediately. The distribution utility shall also be notified prior to return to service through each distribution utility's designated point of contact.

(b) **General interconnection and protection requirements for all DER facilities.** This subsection applies to all DER facilities.

(1) The DER facility and all customer equipment must meet all applicable national, state, and local construction and safety codes.

(2) The DER facility shall be equipped with protective hardware and software designed to prevent the generator from being connected to a de-energized circuit owned by the utility and shall be subject to the utility's inspection and approval.

(3) The DER facility shall be equipped with the necessary protective hardware and software designed to prevent connection or parallel operation of the DER facility with the utility system and shall be subject to the utility's inspection and approval unless the utility system service voltage and frequency is of normal magnitude.

(4) Certified customer equipment may be used in accordance with an approved interconnection control and protection scheme without further review of their design by the utility. When the customer is exporting to the distribution system using certified customer equipment, the protective settings and operations shall be those specified by the utility.

(5) The customer will be responsible for installing protection devices and schemes on its DER facility in such a manner that system outages, short circuits or other disturbances including zero sequence currents and ferro resonant over-voltages do not damage the system, the DER facility, or the facilities of other customers on the system. The customer's protective equipment shall also prevent unnecessary tripping of the distribution system breakers that would affect the system's capability of providing reliable service to other customers.

(6) The utility may require that communication and telemetry channels be provided by the customer to provide communication and telemetry between the utility and the customer's facility.

(7) Circuit breakers or other interrupting devices at the point of common coupling must be capable of interrupting maximum available fault current. DER facilities with nameplate ratings larger than two MVA and operating in parallel to the distribution system shall have a redundant circuit breaker unless a listed device suitable for the rated application is used.

(8) The customer will furnish and install a manual disconnect device approved by the utility that has a visual break that is appropriate to the voltage level (a disconnect switch, a draw-out breaker, or fuse block), and is freely accessible to and operable by utility personnel at any time, and capable of being locked in the open position. The customer shall follow the utility's switching, clearance, tagging, and locking procedures, which the utility shall provide for the customer.

(c) **Prevention of Interference and Control, Protection, and Safety Equipment:** Figure: 16 TAC § 25.212(c)

(d) **Inspection and start-up testing.** The customer shall provide the utility with notice at least two weeks before the initial energizing and start-up testing of the customer's DER facility and the utility may witness the testing of any customer equipment and protective systems associated with the interconnection. The customer shall revise and re-submit the application with information reflecting any proposed modification that may affect the safe and reliable operation of the distribution system. The customer shall confirm with the distribution utility all essential equipment is operational and functioning as designed at least two working days prior to testing date.

(e) **Site testing and commissioning.** Testing of protection systems shall include procedures to functionally test all protective elements of the system up to and including tripping of the DER facility and interconnection point. Testing will verify all necessary protective set points and relay/breaker trip timing. The utility may witness the testing of installed switchgear, protection systems, and DER facility.

(f) **Maintenance.** The customer shall maintain its DER facilities and control and protective customer equipment to prevent adverse impacts on the distribution system and to other customers on the distribution system, and will maintain records of all maintenance activities, which the utility may review at reasonable times. For DER facility systems greater than 500 kVA, a log of DER facility operations shall be kept. At a minimum, the log shall include the date, DER facility time on, and DER facility time off, and mega Watt and mega VAR output. The utility may review such logs at reasonable times.

(g) **Metering.** Consistent with Chapter 25, Subchapter F of this title (relating to Metering), the utility may supply, own, and maintain all necessary meters and associated equipment to record energy deliveries to the point of common coupling and energy exports from the point of common coupling. The customer shall supply at no cost to the utility a suitable location on its premises for the installation of the utility's meters and other utility equipment.

Figure: 16 TAC § 25.212(c)

Prevention of Interference and Control, Protection, and Safety Equipment

(a) **Prevention of interference requirements for legacy distributed energy resources.** This subsection applies only to DER facilities that were interconnected to the distribution system prior to [INSERT DATE] (legacy DER facilities). If a DER Facility 1 MVA or greater are capable of making non-substantial changes/upgrades to adhere to section (b) as determined by the Utility, they will be required to upgrade at the request of the Utility. To eliminate undesirable interference caused by operation of the customer's DER facility, the customer's DER facility must meet the following criteria:

(1) **Voltage.** The customer will operate its DER facility in such a manner that the voltage levels on the distribution system are in the same range as if the DER facility were not connected to the distribution system. The customer shall provide an automatic method of disconnecting the generating equipment DER facility from the 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 +10% or –30% from nominal voltage persists for more than ten cycles. The customer may reconnect when the distribution system voltage and frequency return to normal range and the system is stabilized.

(2) **Flicker.** The customer's equipment shall not cause excessive voltage flicker on the distribution system. This flicker shall not exceed 3.0% voltage dip, in accordance with Institute of Electrical and Electronics Engineers (IEEE) 519 as measured at the point of common coupling.

(3) **Frequency**. The operating frequency of the customer's DER facility shall not deviate **more** than +0.5 Hertz (Hz) or –0.7 Hz from a 60 Hz base. The customer shall automatically disconnect the DER facility from the distribution system within 15 cycles if this frequency tolerance cannot be maintained. The customer may reconnect when the distribution system voltage and frequency return to normal range and the system is stabilized.

(4) **Harmonics.** In accordance with IEEE 519 the total harmonic distortion (THD) voltage shall 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 **common** coupling.

(5) **Fault and line clearing.** The customer shall automatically disconnect from the distribution system within ten cycles if the voltage on one or more phases falls below -30% of nominal voltage on the distribution system serving the customer premises. This disconnect timing also ensures that the generator is disconnected from the distribution system prior to automatic re-close of breakers. The customer may reconnect when the distribution system voltage and frequency return to normal range and the system is stabilized. To enhance reliability and safety and with the utility's approval, the customer may employ a modified relay scheme with delayed tripping or blocking using communications equipment between customer and company.

(b) **Prevention of interference for new distributed energy resources.** This subsection applies only **to** DER facilities that are interconnected to the distribution system on or after [INSERT DATE] and to legacy DER facilities that install new equipment or undergo a substantial modification, such as replacing non-functioning equipment, after [INSERT DATE]. These systems will be classified as new DER facilities and will be required to meet the following criteria:

(1) **Enter Service and Synchronization** When **entering** service, the DER shall not energize the local distribution utility until voltage, system frequency, and phase angle difference are within the ranges specified in Table Enter Service Criteria below:

Enter Service Criteria		
Applicable voltage within range	Minimum	91.70%
	Maximum	105%
Frequency within range	Minimum	59.5 Hz
	Maximum	60.1 Hz
Phase Angle Difference	0-500 kVA	Within 20°
	>500-1500 kVA	Within 15°
	>1500 kVA	Within 10°

(2) **Voltage.** The customer will operate its DER facility and customer equipment in such a manner that its operation shall not cause the voltage levels in the distribution system to be outside the same normal operating voltage range as defined in 17 TAC § 25.51 **for** power quality. A DER facility interconnected at voltages from 1kV to 60kV shall not cause step or ramp changes in the root mean squared (RMS) voltage at the point of common coupling exceeding 3% of nominal and exceeding 3% per second averaged over a period of one second. DER facilities interconnected at a voltage less than 1kV shall 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. New DER systems shall have an automatic method of disconnecting the DER facility from the distribution system if sustained voltage deviations occur. The customer may reconnect when the distribution system voltage and frequency return to normal range and the system is stabilized. The Company may require additional operational or protective devices and coordination.

(3) **Voltage-Power (Active or Reactive) Mode**
The default operating state of this mode shall be disabled. If required by Distribution Utility, settings will be coordinated between Distribution Utility and customer and defined within an interconnection agreement.

(4) **Voltage Tripping and Ride Through.** For DER, customer will operate in accordance with the following tables in abnormal conditions:

Table i: Device Response in Abnormal Voltage Conditions – Inverter Based Devices

Table ii: Device Response in Abnormal Voltage Conditions –Non-Inverter Based Devices

	Table i: Device Response in Abnormal Voltage Conditions – Inverter Based Devices		
Shall Trip Function		Default Setting*	
	Voltage (percent of nominal voltage)	Minimum ride through time (seconds)	Maximum Clearing Time (seconds)
OV3	≥ 120 %	N/A	0.16
OV2	≥ 110 %	12	13.0
OV1	> 105 %	299	300
	normal operating range 90 ≤ x ≤ 105%*		
UV1	< 90%	299	300
UV2	≤ 70 %	20	21.0
UV3	≤ 50 %	1	2.0

	Table ii: Device Response in Abnormal Voltage Conditions –Non-Inverter Based Devices		
Shall Trip Function		Default Setting*	
	Voltage (percent of nominal voltage)	Minimum ride through time (seconds)	Maximum Clearing Time (seconds)
OV3	≥ 120 %	N/A	0.16
OV21	≥ 110 %	1	2.0
OV1	> 105 %	299	300
	normal operating range 90 ≤ x ≤ 105%*		
UV1	< 90 %	Linear slope of 4 seconds / 100% voltage starting at 0.7 s@ 70 %	300
UV2	≤ 70 %	0.16	2.0
UV3	≤ 45 %	N/A	0.16

*Normal Operating Range based on ANSI C84.1 Range A requirements. Excursions beyond the normal operating voltage (i.e., the setpoints) are required to be continuous for ride through and tripping durations. Resets are immediate when dropping below (for high)/going above (for low) the setpoint. The Company may specify/modify other tripping percent range and clearing time trip settings and may require additional operational or protective devices and coordination. The impact to the operation of the Distribution Utility should be considered in determining appropriate time for implementing settings. Failure to carry out a settings change within the applicable timeframe requested by the Distribution Utility may result in temporary disconnection. The timeframe required for the DER Operator to update settings and implement changes should not be longer than three (3) business days.

(5) **Frequency Tripping, Ride Through, and Rate of Change of Frequency.** The customer's DER facility shall use the following default frequency tripping, ride through settings, and rates of change of frequency within the continuous operation region and the low-frequency and high frequency ride-through operational regions over an averaging window of at least 0.1 second during abnormal conditions.

Inverter and Non-Inverter Settings (Given ERCOT Requirements for Transmission Generation)			
Device Requirements in Abnormal Frequency Conditions			
	Default Settings*		
Frequency (Hz)	Ride-Through Mode	Minimum Ride-Through Time (seconds)	Maximum Clearing Time (seconds)
$f > 61.8$	No ride-through requirements**	0.1**	0.16**
$61.6 < f \leq 61.8$	Mandatory Operation	30	31.0
$60.6 < f \leq 61.6$	Mandatory Operation	540	541
$59.4 \leq f \leq 60.6$	Continuous Operation	Duration of Abnormal Condition	Normal Operating Range
$58.4 \leq f < 59.4$	Mandatory Operation	540	541.0
$58.0 \leq f < 58.4$	Mandatory Operation	30	31
$f \leq 58.0$	Mandatory Operation	2	3

Inverter and Non-Inverter Settings (Distribution Table)			
Device Requirements in Abnormal Frequency Conditions			
	Default Settings*		
Frequency (Hz)	Ride-Through Mode	Minimum Ride-Through Time (seconds)	Maximum Clearing Time (seconds)
f > 61.8	No ride-through requirements		0.16
61.2 < f ≤ 61.8	Mandatory Operation	299	300.0
58.8 ≤ f ≤ 61.2	Continuous Operation	Duration of Abnormal Condition	Normal Operating Range
57.0 ≤ f < 58.8	Mandatory Operation	299	300.0
f ≤ 57.0	No ride-through requirements		0.2

Rate of Change of Frequency Ride Through for Synchronous Devices (Low DER Adoption based on reliability/power quality)	Rate of Change of Frequency Ride Through for Inverter Devices (Very High DER Adoption based on reliability/power quality)
0.5 Hz/s	3.0 Hz/s

*The Utility may specify other frequency tripping and clearing time trip settings and may require additional operational or protective devices and coordination.
**Frequency is calculated over a window of time. Typical window/filtering lengths are three to six cycles (50 – 100 milliseconds). Instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible.

(6) **Frequency-droop.** Each DERfacility shall have frequency droop parameters set to 5% at 0.017 hertz (Hz) and will cease to energize and trip if exceeded. The customer may reconnect when the distribution system voltage and frequency return to normal range and the system is stabilized. The Utility may specify other frequency-droop tripping and clearing time trip settings and may require additional operational or protective devices and coordination. The Company may specify other frequency tripping and clearing time trip settings and may require additional operational or protective devices and coordination.

(7) **Flicker.** A DER facility shall not cause excessive voltage flicker on the utility system. Flicker shall be measured and assessed by methods defined in IEEE 1453 and shall not exceed the following limitations:

EP_{st}	EP_{lt}
0.35	0.25

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

EP_{lt} is the emission limit for long-term flicker severity, P_{lt}. If not specified differently, the P_{lt} evaluation time is 2 hours.

*The Utility may specify other flicker settings and clearing time trip settings and may require additional operational or protective devices and coordination.

(8) **Harmonics.** The total rated current distortion (TRD) at the point of common coupling shall not exceed the percent values of current distortion specified below:

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	2	1.5	0.6	0.3	5
Individual even Harmonic order h	h=2	h=4	h=6	8<h<50		
Percent (%)	1	2	3	Range and limits as defined for odd harmonics		

The total rated current distortion (TRD) can be calculated using equation:

$\%TRD = (\sqrt{(I^2_{rms}-I^2_1)}/I_{rated})$ X 100% where:

I_1 – fundamental current as measured at PCC
I_{rated} – DER rated current capacity (transformed to the PCC when a transformer exists between the DER and the PCC).
I_{rms} – Root Mean Square of DER current inclusive of all frequency components as measured at the PCC

The Company may require additional operational or protection devices and coordination of operations, or, upon mutual agreement between the Company and Customer, the DER facility may inject current distortion in excess of these tables.

(9) **Fault and line clearing.** For short-circuit faults on the distribution system to which a DER facility is connected, the DER facility shall cease to energize and trip within 2 seconds unless otherwise specified by the utility. A DER facility shall also detect and cease to energize and trip all phases to which the facility is

connected for any open-phase condition. The facility shall cease to energize and trip within 2 seconds of the open-phase condition unless otherwise specified by the utility. A DER facility shall detect any unintentional island condition and, within 2 seconds of the formation of the island, shall cease to energize and trip unless otherwise specified by the utility. The facility shall not remain connected to or energize a de-energized circuit owned by the utility unless otherwise specified by the utility. When restoring output after momentary cessation, the restore output settings of the DER facility shall be coordinated with the utility's reclosing timing. A DER facility shall 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 utility. The disconnect timing ensures that the DER facility is disconnected from the distribution system prior to automatic re-close of breakers. The customer may reconnect when the distribution system voltage and frequency return to normal range and the system is stabilized. To enhance reliability and safety and with the utility's approval, the customer may employ a modified relay scheme with delayed tripping or blocking using communications equipment between customer and company. The customer may reconnect when the distribution system voltage and frequency return to normal range and the system is stabilized.

(10) **Intentional islanding using utility equipment.** An intentional island using Utility equipment shall be designed and operated in coordination with Utility personnel and documented including those details of operation within the interconnection agreement supplemental terms and conditions. Utility personnel shall be notified when an intentional island is operated (when scheduled, at least 3 days in advance or, when unscheduled, as soon as possible).

(c) **Control, protection and safety equipment requirements specific to single phase DER facilities**. This subsection applies to both legacy and new DER facilities. Exporting to the distribution **system** may require additional operational or protection devices and will require coordination of operations with the host utility.

(1) **Control, protection and safety equipment requirements specific to single phase DER facilities**. The necessary control, protection, and safety customer equipment specific to single-phase DER facilities in the aggregate connected to secondary or primary distribution systems typically include an interconnect disconnect device, a DER facility disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and a synchronizing check for synchronous and other types of DER facilities with stand-alone capability. The utility may require additional operational or protection devices and coordination of operations.

(d) **Control, protection and safety equipment requirements specific to three-phase synchronous DER facilities, induction DER facilities, and inverter systems.** This subsection applies to both legacy and new DER facilities and specifies the typical control, protection, and safety equipment requirements specific to three phase synchronous DER facilities, induction DER facilities, and inverter systems. Exporting to the distribution system may require additional operational or protection devices and will require coordination of operations with the utility.

(1) **Three phase synchronous DER facilities.** The circuit breakers for three-phase synchronous DER facilities shall be three- phase devices. The customer is solely responsible for properly synchronizing its DER facility with the utility. The excitation system response ratio shall not be less than 0.5. The facility's excitation system(s) shall conform, as near as reasonably achievable, to the field voltage versus time criteria specified in all applicable American National Standards Institute and/or IEEE Standards to permit adequate field forcing during transient conditions. For DER facilities two MVA or greater the customer shall maintain the automatic voltage regulator (AVR) of each DER facility unit in service and operable at all times. If the AVR is removed from service for maintenance or repair, the customer is responsible to immediately contact each Distribution Utility representative (i.e. Distribution Accounts Rep, Large Customer C&I, Dispatch Center, etc.) and the DER facility shall be placed out of service until the AVR is returned to service and the distribution utility shall be notified.

(2) **Three-phase induction and inverter DER facilities.** Induction DER facilities may be connected and brought up to synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured on the distribution system side at the point of common coupling is within the applicable visible flicker stated in subsection (a)(2) or (b)(7) of this section. Otherwise, the customer may be required to install hardware or employ other techniques to bring voltage fluctuations to acceptable levels. Direct-current DER facilities shall not be operated in parallel with the distribution system.

(3) **Protective function requirements.** The typical protective function requirements for three phase facilities of different size and technology are listed below. The utility may require greater protective function requirements based on pre-interconnection studies.

i. DER facilities with a nameplate rated ten kilovolt-amperes (kVA) or less must have an interconnect disconnect device, a DER facility disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and a manual or automatic synchronizing check (for facilities with stand-alone capability).

ii. DER facilities with a nameplate rated in excess of ten kVA but not more than 500 kVA must have an interconnect disconnect device, a DER facility disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, a manual or automatic synchronizing check (for facilities with stand-alone capability), either a ground over-voltage trip or a ground over- current trip depending on the grounding system if required by the utility, and reverse power sensing if the facility is limiting its export capability. Communication based telemetry and/or transfer trip may also be required by the company as part of a transfer tripping or blocking protective scheme.

iii. DER facilities with a nameplate rated more than 500 kVA but not more than 2 MVA must have an interconnect disconnect device, a DER facility disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, either a ground over-voltage trip or a ground over- current trip depending on the grounding system if required by the company, an automatic synchronizing check (for facilities with stand-alone capability) and reverse power sensing if the facility is limiting its export capability. If the facility is exporting power, the power direction protective function may be used to block or delay the under-frequency trip with the agreement of the utility. Communication based telemetry and/or transfer trip may also be required by the company as part of a transfer tripping or blocking protective scheme.

iv. DER facilities with a nameplate rated more than 2 MVA must have an interconnect disconnect device, a DER facility disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, an automatic synchronizing check and AVR for facilities with stand-alone capability, and reverse power sensing if the facility is limiting its export capability. If the facility is exporting power, the power direction protective function may be used to block or delay the under-frequency trip with the agreement of the utility. Communication based telemetry and/or transfer trip may also be required by the company as part of a transfer tripping or blocking protective scheme.

(e) **Facilities not identified.** In the event that standards for a specific DER or other type of distribution resource facility or system are not set out in this section, the utility and customer may interconnect such facility or system using mutually agreed upon technical standards.

(f) **Requirements specific to a new DER facility paralleling for 100 milliseconds or less (high speed closed transition switching).** The protection requirements for facilities defined in Table AMR in Article 25.211 which parallel with the distribution system for 100 milliseconds or less are exempted from section (a) and (b) above. These DER facilities require an interconnect disconnect device, a generator disconnect device, a breaker failure scheme, and an automatic synchronizing check for DER facilities with stand-alone capability. Customer may be required to provide to the utility test reports that demonstrate that the system operated in less than 100ms 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.