PROJECT NO. 39797

RULEMAKING TO IMPLEMENT SB 365 & SB 981 RELATING TO DISTRIBUTED GENERATION	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ADOPTING AMENDMENTS TO §25.211 AND §25.217 AS APPROVED AT THE MAY 18, 2012 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts amendments to §25.211, relating to Interconnection of On-Site Distributed Generation (DG), with changes to the proposed text and §25.217, relating to Distributed Renewable Generation without changes to the proposed text as published in the December 23, 2011 issue of the *Texas Register* (36 TexReg 8694). The amendments implement statutory changes resulting from the passage of Senate Bills 365 and 981 of the 82nd Legislature, Regular Session in 2011 (SB 365 and SB 981). Specifically, the amendments to §25.211 limit the applicability to cooperatives to the requirements outlined in subsection (o); modify the definition of parallel operation to recognize third-party DG ownership; place the burden on the DG owner to report any changes in ownership or cessation of operations to the electric utility; and modify subsection (o) to more accurately track the language in PURA §35.036(b) and (f). The amendments to §25.217 constitute a competition rule subject to judicial review as specified in PURA §39.001(e). These amendments are adopted under Project Number 39797.

The commission received comments on the proposed amendments from City of Houston (Houston), City of El Paso (El Paso), Oncor Electric Delivery Company LLC, El Paso Electric Company (EPE), Solar Energy Industries (SEIA), Interstate Renewable Energy Council (IREC), CenterPoint Energy Houston Electric (CenterPoint), LLC, Golden Spread Electric Cooperative, Inc. (Golden Spread), East Texas Electric Cooperative, Inc. (ETEC), South Texas Electric Cooperative, Inc. (STEC), Texas Electric Cooperatives, Inc. (TEC), Lone Star Chapter of the Sierra Club (Sierra Club), Texas Renewable Energy Industries Association (TREIA), Lennar Ventures (Lennar), AEP Texas Central Company, AEP Texas North Company, and Southwestern Electric Power Company (AEP Companies), Southwestern Electric Power Company (SWEPCO), Southwestern Public Service Company (SPS), Entergy Texas, Inc. (ETI), and the Retail Electric Provider Coalition (REP Coalition).

The REP Coalition was composed of the Alliance for Retail Markets (ARM); CPL Retail Energy, LP; Reliant Energy Retail Services, LLC; WTU Retail Energy, LP; TXU Energy Retail Company LLC; the Alliance for Retail Markets (ARM); and Texas Energy Association for Marketers (TEAM). The participating members of ARM with respect to the REP Coalition comments were: Direct Energy, LP; Gexa Energy, LP; and Green Mountain Energy Company. The participating members of TEAM with respect to the REP Coalition comments were: Accent Energy; Amigo Energy; Bounce Energy; Cirro Energy; Energy Plus; Green Mountain Energy Company; Just Energy; Hudson Energy Services; StarTex Power; Stream Energy; Tara Energy; Texas Power; and TriEagle Energy.

Summary of Comments

Section 25.211

Subsection (a); Applicability

STEC and TEC questioned the need for §25.211's applicability to electric cooperatives. STEC further felt that the commission exceeded its authority by mandating that certain terms of service in §25.211 are applicable to electric cooperatives' interconnection of distributed natural gas facilities. Sierra Club, TEC, and STEC maintained in their reply comments the opinion that the commission exceeded its authority by mandating certain terms of service in this rule. Further, TEC and STEC questioned the need for this rule to be applicable to cooperatives.

TEC commented that it supported the passage of SB 365. Because a distributed natural gas generation facility must be two MW or less, TEC stated that it believes almost all of the interconnections for these facilities with the grid will be at distribution voltages and any wheeling will necessarily include wheeling at distribution voltages. TEC asserted that the commission overstepped its jurisdiction by proposing to include electric cooperatives in its interconnection rules. Moreover, TEC stated that many provisions of the proposed interconnection rules are not applicable to electric cooperatives as currently drafted and the entire rule would largely have to be rewritten if the commission denies the jurisdictional challenge and applies the rules to electric cooperatives.

TEC requested that the commission remove from the proposed rules the references to electric cooperatives and distributed natural gas facilities. TEC stressed that only certain limited provisions of the Texas Utilities Code apply to electric cooperatives, as instructed by the legislature. Those provisions are mainly contained in the Texas Utilities Code, Chapter 35 Subchapter A, §39.002, and §41.004. TEC opined that upon examination, those provisions make clear that the commission does not have jurisdiction to adopt interconnection rules applicable to electric cooperatives and a distributed natural gas facility. TEC added that SB 365 does not change the current regulatory scheme, but only refers to rules regarding the use of transmission and distribution facilities for wheeling, which is distinguishable from interconnection. TEC recommended that electric cooperatives should continue to provide access to their facilities and file open access tariffs, as provided in §25.191(d)(2)(C).

As discussed in further detail in the next section, EPE argues that pursuant to PURA §39.551, §25.211 does not apply to them. EPE stated that the proposed changes to this subsection strike certain language that exempted EPE from the rule. However, EPE interpreted staff's amendment to subsection (b) to exempt EPE from the rule. EPE sought clarification on whether EPE remains exempt from §25.211.

Golden Spread offered several options for addressing the issues raised by the cooperatives concerning the application of the interconnection rules to cooperatives (discussed in more detail in subsection (o)). One option included modifying the language in subsection (a) to clarify that only subsection (o) of this rule applies to cooperatives.

Commission response

The commission agrees with Golden Spread that this section should be modified to limit the applicability of this rule to electric cooperatives only as the rule pertains to distributed natural gas generation facilities, as outlined in subsection (o). The commission has modified this subsection accordingly. The commission finds that §25.211 and §25.217 do apply to EPE for the reasons discussed below.

The commission declines to delete the provisions applicable to cooperatives and adopts changes to subsection (o) suggested by Golden Spread, Oncor, and the REP Coalition discussed below.

Subsection (b); Purpose

The striking of certain language within this subsection was of particular concern to IREC. IREC's position was that the language contained in this subsection provided a useful explanation as to why the commission originally adopted this rule; and, while not absolutely necessary, this language was a reminder of why the rule was needed and should be retained. EPE asserted that the striking of this language appeared to show staff's intent, as amended, that the rule still does not apply to EPE. EPE interpreted the language to mean that EPE remains exempt from the provisions of §25.211, and therefore requested clarification on that point. EPE noted that pursuant to §39.551, it is not subject to PURA §39.101(b)(3). Further, EPE stated that the rule, as amended, states that sales of power intrastate, i.e., Texas, are under the open-access transmission service of ERCOT; and it (EPE) is not under that service, but under the Federal Energy Regulatory Commission (FERC) Open Access Transmission Tariff (OATT) service. EPE's position was that all of its transmission in Texas is regulated under its FERC OATT. Accordingly, from EPE's standpoint, pursuant to the proposed language, whereas EPE is not located in ERCOT, it appears that the rule does not apply to EPE.

In reply comments ETI submitted that the rule does not apply to ETI for the reasons given by EPE in its initial comments. ETI contented that the proposed language makes clear that the sales of power by on-site DG in the intrastate wholesale market are subject to the provisions of

Chapter 39 of PURA, related to open-access comparable transmission service for utilities in ERCOT. ETI maintained the same argument as EPE that it is not subject to the open-access transmission service requirements in ERCOT, but rather is subject to the FERC Open Access Transmission Tariff (OATT). In addition, ETI opined that PURA §39.452 exempted it from Chapter 39, except in very limited circumstances. Consequently, PURA §39.101(b)(3) related to DG and §39.916 regarding distributed renewable generation (DRG) would not be applicable to ETI.

The AEP Companies (namely SWEPCO) also maintained the position that the commission should clarify that this rule is not intended to apply to the interconnection of DG facilities outside of ERCOT.

Commission response

Concerning IREC's comment that the commission should retain the language about why the commission originally adopted this rule, the commission declines to do so because the language is unnecessary and clutters the rule. However, the commission has clarified the reference to the provisions relating to open-access comparable transmission service.

The commission rejects the comments of EPE and the AEP Companies (namely SWEPCO) that §25.211 and §25.212 should not apply to them. As stated in proposed subsection (a), §25.211 and §25.212 are intended to apply to an electric utility for all purposes unless the context indicates otherwise. The statement in subsection (b) about the intrastate market does not limit the rule to DG in the intrastate market, and the rules should apply to all

electric utilities except where they are preempted by federal law. In addition, although the specific impetus for the original adoption of §25.211 and §25.212 was the enactment of PURA §39.101(b)(3) in 1999, the commission had approved DG interconnection guidelines before the adoption of PURA §39.101(b)(3) under its pre-existing authority and requested that staff continue its investigation of DG. Sections 25.211 and 25.212 were originally adopted in the November 18, 1999 open meeting in Project No. 21220 and applied to most non-ERCOT utilities. Since then, various exemptions from parts of PURA Chapter 39 for non-ERCOT utilities have been added. However, it is in the public interest for customers to have the right to DG even for utilities that are not currently subject to PURA §39.101(b)(3), because DG is an important source of generation.

Subsection (c)(4); Definition of Distributed Natural Gas Generation Facility

SEIA suggested that there may be an inconsistency in the definition of facilities. SEIA stated that the addition of the new statutory definition of "distributed natural gas generation facility" in this subsection may be construed to conflict with the existing definition of "facility" in subsection (c)(5). Specifically, the strict 2,000 kilowatt limit for distributed natural gas facilities behind the customer's side of the meter in proposed subsection (c)(4) could possibly be construed to conflict with the existing definition of facility's allowance that "the total capacity of a facility's individual on-site DG units may exceed ten megawatts (MW); however, no more than ten MW of a facility's capacity will be interconnected at any point in time at the point of common coupling under this section." SEIA suggested that these two paragraphs taken together could be interpreted such that a facility may include 10 or more megawatts from a variety of DG sources, but that only 2,000 kilowatts may come from natural gas. SEIA requested clarification on the definition of facility in this instance.

Lennar suggested that there may be some confusion between the use of the terms “distributed natural gas generation” and “on-site distributed generation.” It stated that these terms are not defined in §25.5. Lennar was particularly concerned that the use of the term on-site distributed generation may place certain obligations on DRG owners that are exempted from the requirements in this rule if they meet the requirements set forth in PURA §39.916(k).

Commission response

Concerning SEIA’s comments, the commission has clarified the definition of facility, including a change, to make it clear that natural gas DG falls within the definition. The definitions of facility and on-site distributed generation allow for generation to use any fuel source. In contrast, PURA provides certain rights that are specific to distributed natural gas facilities. A facility may take advantage of these rights if it falls within the definition of distributed natural gas generation facility.

Concerning Lennar’s comments, “distributed natural gas generation facility” and “on-site distributed generation” are defined in §25.211(c). In addition, Lennar did not identify any part of §25.211 that is inconsistent with PURA §39.916(k).

Subsection (c)(11); Definition of Parallel Operation

SEIA proposed that staff clarify the definition of "parallel operation." The current rule defines parallel operation as "the operation of on-site distributed generation by a customer while the customer is connected to the company's utility system" and subsection (c)(6) defines "interconnection" as having the intended result that a customer qualifies as a DRG owner if DRG is located on the customer's side of the meter. SEIA maintained that the parallel operation and interconnection definitions imply that a customer must operate the DRG to be a DRG owner. SEIA suggests clarifying the proposed language by changing the definition of parallel operation to state "the operation of on-site distributed generation located on the customer's side of the meter while the customer is connected to the company's utility system."

Commission response

The commission agrees that with the modifications to §25.217, which add third-party owners to the definition of DRG owner, the reference in the definition of parallel operation to operation by a customer should be deleted. The commission has changed the definition accordingly.

Subsection (d); Terms of Service

STEC and Golden Spread commented that the commission has limited authority over cooperatives for purposes of wholesale transmission rates and services, including terms of access. STEC argued that the commission has exceeded its authority in trying to apply §25.211(d)(2)-(3) of the proposed rule to cooperatives. STEC argued that the commission exceeds its authority under PURA §41.004, which authorizes the commission to establish terms and conditions for open access, but not rates, for cooperatives providing customer choice; PURA §41.055(l) which requires that rates established by a cooperative's board of directors be nondiscriminatory and comparable to the distribution rates that apply to the cooperative and its subsidiaries; PURA §41.055(6), (9) and (11) which grants a cooperative's board of directors exclusive jurisdiction to manage and operate the cooperatives system, including control over resource acquisition and expansion and other decisions affecting the cooperatives method of conducting business; and PURA §41.101 which prohibits the commission from using anything in the subtitle to interfere with or abrogate the rights of obligations of parties, including a retail or wholesale customer, to a contract with an electric cooperative. ETEC indicated that the proposed rule reduces the authority granted to cooperative boards of directors by the legislature in PURA §41.005. STEC and ETEC also noted that §25.211(d)(2)-(3) conflicts with PURA §35.004(a) and (c) which mandate that the utility recover the costs of providing service from the entity for which the transmission is provided. STEC argued that it is clear that the commission has no jurisdiction over the distribution rates charged by a cooperative whether they have adopted customer choice or not. However, STEC and Golden Spread also pointed out that PURA §35.036(f) grants the commission the authority to resolve a dispute at the request of the owner or operator of the distributed natural gas facility.

Golden Spread and STEC commented that electric cooperatives have not previously been subject to the commission's rules regarding DG; however, the proposed amendments would apply to an electric cooperative with respect to a distributed natural gas facility. Golden Spread, ETEC, and

TEC anticipated that its members may receive requests for DG and “free wheeling” (a pricing scheme that includes free wholesale service which is required under §25.211(d)(2)-(3) of the proposed rule) and were concerned with fair treatment of wheeling costs. Golden Spread maintained that free wheeling is not required by SB 365. ETEC believed that the prohibition against charging a DG owner for transmission or distribution-related service goes beyond the scope of the legislation and should not be adopted, because the legislation itself states that electric utilities or electric cooperatives may recover the reasonable costs of interconnecting the facility. ETEC goes further and states that SB 365’s reference to “rules” was intended to refer to open access rules, not intended to refer to interconnection rules.

Golden Spread believed that free wheeling is highly unfair to those customers who support the cost of transmission systems used to provide such wheeling. Golden Spread commented that free wheeling that is offered to a particular customer group appears to be discriminatory, which is contrary to PURA §35.004 and federal law and policy. ETEC, Golden Spread, and TEC asserted, and STEC supported in its reply comments, that cooperatives will be required to pass on these additional costs to their current non-DG members. ETEC noted that this would result in cooperatives paying for costs that cannot be attributable to them and may subject cooperatives to future legal risks. Golden Spread further asserted that since a distributed natural gas generation facility is limited to 2,000 kilowatts most, if not all, interconnections will occur at distribution voltages where the line losses typically are relatively high. Golden Spread also indicated that the costs of providing free wheeling for a small cooperative is high and increases with capacity and energy costs and provided a table that shows the potential impact.

Golden Spread and ETEC were also concerned that the proposed rules conflict with The Fifth Amendment to the United States Constitution, which prohibits the government from taking private property for public use without just compensation; federal energy law and policies applicable to interconnection, transmission wheeling, and rates for transmission service under the Federal Power Act and FERC regulations; and, possibly, Regional Transmission Organization (RTO) requirements. ETEC commented that the Texas Constitution also prohibits a person's property from being applied to public use without adequate compensation.

While Oncor and CenterPoint raised concerns about the proposed language in subsection (o) departing from the statutory language in PURA §35.036(b), the AEP Companies posited in its reply comments that the rule, as written, may provide for free wheeling irrespective of the existing regulatory structure for wholesale transmission, because the language in subsection (o) does not reference the applicable commission rules or a FERC tariff.

In its reply comments, Golden Spread reiterated its opposition to the application of the commission's interconnection rules to electric cooperatives, in large measure because proposed §25.211(d)(2) prohibits charges for operation and maintenance of a utility system's facilities. Golden Spread objected to the application of subsection (d)(3) to cooperatives, which prohibits transmission charges associated with wheeling for a customer exporting energy, on the basis that such provisions prohibit the imposition of any charges for use of a cooperative's poles and wires to provide transmission and requires the cooperative to provide for free the energy associated with line losses. Golden Spread noted in its reply that its position is shared by TEC, STEC, and ETEC. Additionally, Golden Spread contrasted FERC/SPP with ERCOT regarding the method of providing transmission service to generators. Golden Spread and SPS were concerned that applying the commission's interconnection provisions of this proposed rule outside of ERCOT's jurisdiction will create conflicts with FERC's rules, and that nowhere is this more evident than in the rates for transmission wheeling. Golden Spread offered three possible solutions to the concerns raised by the electric cooperatives: (1) the commission could continue to apply its open access rules (§§25.191 - 25.203) to electric cooperatives but not apply its interconnection rules through the proposed DG rule to electric cooperatives; (2) the commission could open a proceeding to modify its open access rules to require utilities outside of ERCOT to file tariffs with FERC within 45 days of receiving a request for wholesale wheeling over distribution voltage facilities; or (3) the commission could modify the proposed interconnection rules to achieve the preceding two Golden Spread solutions based on modifications offered by Golden Spread to subsections (a) and (p).

In its reply comments, STEC strongly supported the comments of ETEC, TEC, and Golden Spread. It stated that ETEC and TEC accurately asserted that the prohibition against charging the distributed natural gas facility for wheeling services would constitute a regulatory taking without just compensation. It also echoed the comments of Golden Spread regarding the unfair treatment created by free wheeling. Even if the cooperatives were excluded from this rule, STEC argued that the cooperatives would not overcharge for wheeling, as load would still be responsible for paying for wheeling of power at the transmission level. At the distribution level, cooperatives would charge cost-based rates as outlined in their tariffs.

Commission response

As explained above, the commission has changed the proposed rule such that only subsection (o) applies to cooperatives. Adopted subsection (o) limits the commission's regulation of a cooperative's interaction with a distributed natural gas generation facility to the authority provided to the commission by recently enacted PURA §35.036 and, by reference to existing rules, relies on the commission's long-standing authority to regulate wholesale transmission service of a cooperative in ERCOT to a power generation facility such as a distributed renewable generation facility.

In addition, to address electric utilities whose wholesale transmission service is subject to FERC jurisdiction, the commission has changed subsection (a) to explicitly state that §25.211 and §25.212 do not apply to the extent preempted by federal law.

In response to the comments of Oncor and CenterPoint, the commission has modified subsection (o) to better track the language in PURA §35.036(b).

Subsection (n); Reporting Requirements

Oncor recommended a change to the proposed reporting requirements under this subsection. Oncor pointed out that it currently has over 1,300 DG facilities on its system and that these are usually small facilities, many are attached to residences, and the premises on which they are attached are often bought and sold without any notification to Oncor. Consequently, Oncor maintained that it has no way of identifying the current owner of the DG system without contacting 1,200 owners/operators annually. Oncor recommended that staff consider amending the DG Interconnection Agreement form to require the DG owner to report to the utility any change in ownership or permanent cessation of operations of the DG facility, thereby requiring the utility to only report the ownership changes and operation cessations that have been reported to it. Oncor offered language that would amend this subsection by stating that "any change in ownership or permanent cessation of operations of any distributed generation that has been reported to the electric utility and not included in a previous report" should be included in the distributed generation owner's annual report to a utility.

CenterPoint recommended that this reporting requirement be deleted altogether. Oncor and CenterPoint offered their respective modifications to this subsection, both of which place the reporting responsibilities of facility ownership and cessation of facility operations on the DG owners.

Sierra Club supported the proposed changes because they should assure that PUC, ERCOT, and the TDUs will have information about the number of systems and be able to utilize this information in transmission and generation planning. Sierra Club offered reply comments reiterating its support for the requirement that transmission utilities report annually on the presence of on-site generators, but agreed that the provision dealing with change in ownership may be difficult. Therefore, Sierra Club supported a change to require utilities to report only when information on ownership or cessation of operation is submitted to them by the owners. STEC and its members, along with SPS and the AEP Companies, supported the comments of Oncor and CenterPoint.

Commission response

The commission recognizes that, as Oncor pointed out, there may be many DG facilities interconnected throughout a utility's service territory. The commission agrees that the DG owners should be required to provide information regarding a change in ownership or the cessation of operations and changed the rule accordingly. Rather than use business days as suggested by CenterPoint, the commission has set a 14-day deadline for a DG owner to provide the information, because a DG owner may not know which days constitute business days for the utility.

The commission notes that Oncor suggested modification of the DG Interconnection Agreement form, which is part of a utility's Tariff for Interconnection and Parallel Operation of Distributed Generation, to require DG owners to report any change in ownership or cessation of operations. The commission will initiate a separate proceeding to modify the interconnection form to reflect the changes to this subsection and to specifically state that the DG owner is responsible for reporting any change in ownership or cessation of operations.

Oncor and CenterPoint offered similar language that clarified that the utility will be required to report only changes in ownership or cessation of operations that are reported to the utility since the previous report. The commission adopts Oncor's language and has amended the rule accordingly.

Old subsection (o); Interconnection Disputes

SEIA directed the commission's attention to the fact that the proposed rulemaking strikes language regarding resolution of complaints, with no accompanying rationale by staff. SEIA and IREC recommended that commission maintain or develop a clear process to address dispute resolution to ensure timely development of DG.

Sierra Club supported reinserting language in this subsection related to dispute resolution, as brought up by SEIA in its initial comments. Sierra Club commented that if 20 days is an unreasonable timeframe for the commission to attempt to resolve complaints, the time could be extended to 30 days. It agreed that there is no fundamental reason to remove this important protection.

Commission response

The commission believes that the procedures for processing an informal and formal complaint outlined in §22.242 adequately address a complaint arising from an interconnection dispute between a distribution generation owner and a utility. Under §22.242, a complainant can file an informal complaint with the commission. Staff must resolve a complaint within 35 days. If Staff does not resolve the complaint to the satisfaction of the complainant, the complainant may present a formal complaint to the commission. This ensures consistent treatment of complaints received that allege violation of any of the commission's rules. Therefore, the commission declines to maintain old subsection (o), as suggested by SEIA, IREC, and Sierra Club.

New subsection (o); Registration Requirements

Oncor agreed with the deletion of the current subsection, but argued that the proposed replacement language is contrary to PURA and should not be adopted. Oncor cited PURA §39.351(a) to emphasize that a person may not generate electricity prior to obtaining a power generation company (PGC) registration from the commission. Oncor then stressed that the person/PGC must register with the commission by filing the required information and that the information cannot be supplied by another entity, but *only* by the PGC itself. Oncor also noted that the registration of PGC/DG facilities was considered in the recent legislative session and that the legislature did not provide a blanket exemption for all DGs; nor did it allow the registration to be made indirectly by a utility report. The legislature chose to require all DG facilities to register themselves as a PGC unless, pursuant to PURA §39.916(k), the facility is a DRG that is estimated at the time of installation to produce less power on an annual basis than the customer will consume. All other DG facilities must register with the commission, with the exception of distributed natural gas generators, as PURA §39.351 grants the commission the authority to establish simplified registration filing requirements for distributed natural gas generators. It is the position of both CenterPoint and Oncor that proposed subsection (o) provides all DG facilities with relief that they did not obtain from the legislature, and that the commission does not have the authority to adopt this subsection. Oncor expressed that this proposed change would effectively make it the registration agent for all other DG facilities within its service territory. As such, Oncor recommended that proposed subsection (o) be deleted and the remaining subsections be renumbered.

Houston supported the addition of this provision and believes that the simplification of the registration process will ultimately encourage further personal investment in DG by retail electric customers.

In its reply comments, the AEP Companies agreed with the comments filed by Oncor and CenterPoint. They stated that the registration process and amendments to the registration are not so onerous that the burden should be shifted from the DG owner to the utility. Further, it argued that the proposed rule could lead to less compliance, as the DG owner would not be subject to any administrative penalties for noncompliance since the burden is on the utility to provide the DG owner's information in an annual report. For example, a power generation company (PGC) is subject to up to a $1,000 a day fine for failing to register or maintain registration.

Lennar commented that it generally supported the rules as proposed. Lennar notes that PURA §39.916(k) relieves DRG owners of the regulatory burden of registering with or being certified by the commission if the customer's estimated annual energy production is less than or equal to the annual energy consumption. Lennar suggested that the commission include language in the preamble that makes clear that §25.211 does not impose reporting or registration requirements on DRG owners who qualify for the treatment set forth in PURA §39.916(k) and §25.217.

Commission response

The commission has deleted proposed subsection (o) and renumbered subsequent subsections accordingly, because it is unclear whether the commission has the authority to permit an on-site distributed generation owner who is a power generation company to

register with the commission through the information it submits to the utility. PURA §39.351(c) does not resolve this uncertainty for an owner of a distributed natural gas generation facility, because the "simplified filing requirements" referred to in that subsection is the "filing" required by PURA §39.351(a). A DRG owner that meets the requirements of PURA §39.916(k) is not a PGC; therefore, the issue is not applicable to such an owner. Nevertheless, the utility and the commission need information from such DRG owners who interconnect their DRG with the utility's system. Therefore, because nothing in PURA prevents the commission from requiring that the utility obtain needed information from these DRG owners, §25.211(n) appropriately requires that these DRG owners provide information like all other DG owners.

Section 25.211(p); Interconnection of Distributed Natural Gas Generation

Houston supported the addition of this provision and favors DRG for its low emissions and lack of dependence on fuel delivery. However, Houston recognized that there are problems of intermittency unique to renewable energy resources, and therefore supported provisions that encourage personal investment in distributed natural gas generation.

CenterPoint requested that the commission not adopt this proposed subsection at all, which in its opinion, adds language not contained in PURA, deletes language that is contained in the statute, and is therefore harmful since the language differs from the provisions in PURA. Oncor is specifically concerned that the first sentence incorporates a reference that is not found in the statute and in its opinion should not be included because it leaves out an important aspect of PURA §35.036(b). Therefore, Oncor proposed a modification to this subsection that more accurately depicts the language in PURA. Additionally, Oncor recommended deleting references to subsections (e) and (f), since PURA §35.036(b) does not incorporate those provisions and therefore such a cross reference is unnecessary. According to Oncor, when a rule incorporates most, if not all, of the statutory language, it raises a question of why the language was excluded. Further, anyone reading the rule and not the statute should be aware of all of the statutory requirements.

The REP Coalition submitted language that, in its opinion, will address the sale and purchase of distributed natural gas generation, in a way similar to how §25.217(e)-(t) currently provides clarification with respect to the sale and purchase of DRG, as required and/or allowed pursuant to PURA §39.916(h) and (j). The REP Coalition believed that language that is very similar to the language in PURA §35.036(a) should be included in subsection (o), which provides that "[a] person who owns or operates a distributed natural gas generation facility may sell electric power generated by the facility. The electric utility, electric cooperative, or retail electric provider that provides retail electricity service to the facility may purchase electric power tendered to it by the owner or operator of the facility at a value agreed to by the electric utility, electric cooperative, or retail electric provider and the owner or operator of the facility."

The AEP Companies commented that this subsection should be amended to conform to the statute. The AEP Companies stated that it agrees with Oncor and CenterPoint that this proposed subsection does not faithfully follow the statutory language of PURA §35.036(b). The AEP Companies' contented that the proposed rule omits some statutory language (the requirement that transmission of power from distributed natural gas generator to another entity be in compliance with commission rules or a tariff approved by FERC) and includes a limiting cross-reference (to subsections (e) and (f) of PURA §35.036) not found in the statutory language. The AEP Companies' suggested that the clause from the statute referencing FERC tariffs be added to this subsection. The AEP Companies believed that the suggestions by Oncor to conform the subsection to the statute or CenterPoint to delete the subsection are both acceptable means of resolving this issue.

If the commission chooses to extend jurisdiction over the cooperatives, Golden Spread offered modifications to subsection (o) to make reference to the commission's open access rules (§§25.191 - 25.203) and to require cooperatives outside of ERCOT to file a tariff with FERC after receiving a request for wholesale transmission service at distribution level voltage. STEC and Golden Spread also pointed out that PURA §35.036(f) grants the commission the authority to resolve a dispute at the request of the owner or operator of the distributed natural gas facility.

Commission response

The commission has changed this subsection to address the subsections of PURA §35.036 that refer to commission rules or the commission; include language addressing PURA §35.036(h); more closely track the language of PURA §35.036; and address the interrelationship between this subsection and other subsections and rules.

General Comments

Houston and Sierra Club supported the proposed amendments to the extent that they facilitate investment in DG by small-scale retail electric customers. Houston believed that DG can play a critical role in mitigating the impact of extended power outages, especially during extreme weather events, which are common in the Houston region. Therefore, Houston supported the commission's efforts to make the DG interconnection and registration process as accessible to small-scale retail electric customers as possible, while preserving the safe and reliable operation of the grid. Sierra Club echoed this support and also commented that, because of proposed changes to reporting by electric utilities, the rules should assure that the commission, ERCOT, and the utilities have information on the number of distributed systems and are able to utilize this information in transmission and generation planning. Sierra Club endorsed the changes required by SB 365, which would allow small distributed natural gas facilities to interconnect within ERCOT.

Net Metering

IREC urged the commission to consider opening a separate proceeding to investigate the benefits of implementing full retail net energy metering (NEM) to fully realize the market expanding potential of third-party ownership of DG. Through the topic of the removal of banking provisions within proposed §25.211 IREC reintroduced the subject of net metering, which it proceeded to point out has been adopted in 43 states across the county. IREC commented that a lack of full retail net metering curtails potential market growth, thereby limiting the potential benefits of the proposed rules. Further, IREC related the benefits of that third-party ownership model (*e.g.*, job creation and further growth of the renewable energy industry) and how it can be optimized in tandem with NEM.

The REP Coalition commented on IREC's request to have the commission initiate an investigation and/or rulemaking proceeding to address NEM, a term that REP Coalition contends is not defined by IREC in its initial comments. The REP Coalition stated that the commission lacks the authority to initiate an investigation or rulemaking based on IREC's concept of NEM. The REP Coalition pointed out that the statute does not require the REP to purchase the excess energy produced by the DRG facility at the same price it charges the DRG owner for retail electric service. Likewise, PURA §35.036(a) allows a distributed natural gas generation owner and the REP serving its load to agree upon the price the REP pays for any electric power made available to the grid by the distributed natural gas facility. The REP Coalition's position was that IREC's request for the commission to initiate a net metering rulemaking project should be rejected.

In their reply comments, Oncor, CenterPoint, the AEP Companies, Sierra Club, and REP Coalition referenced P.U.C. Project No. 34890, *Rulemaking Proceeding Relating to Net Metering and Interconnection of Distributed Generation*, a project involving an in-depth analysis of whether net metering should be adopted in Texas. CenterPoint also referenced House Bill 3693 (80^{th} R, 2007) related to metering and the preamble language to the adoption of §25.213. Oncor highlighted the fact that the commission conducted a year-long process of adopting rules relating to DG metering and interconnection, renewable energy credits, and the sale of out-flows for DRG, a project in which IREC strongly supported the adoption of rules that would allow net metering. Oncor noted that the commission concluded, however, that a net metering approach would be in violation of PURA. Oncor's position was that there is no need, nor any legal basis, to open a new proceeding to examine net metering; and further, IREC's recourse should be aimed at the legislature and not the commission. The REP Coalition and CenterPoint shared this opinion.

The AEP Companies further stated that the legislature's decision in adopting SB 1910 (now codified in PURA §39.554(e)) demonstrates that the type of net metering IREC proposes can be used for limited purposes in EPE's service territory. If the legislature had intended for the type of net metering IREC proposed to be offered statewide, the legislature could have amended PURA §39.914(d) and §39.916(f).

Sierra Club stated that, while it agrees with the spirit of the comments filed by IREC on net metering, it does not think such provisions can be accomplished in the present rulemaking.

Commission response

The issue of net metering was previously addressed in Project No. 34890. As Oncor accurately quoted in its comments regarding the previous rulemaking, the commission found the position of IREC and Public Citizen regarding netting over the billing period to be inconsistent with PURA §39.914(d) and §39.916(f), and further stated in a subsequent order that these sections of PURA do not differentiate whether the meters are located in an area with customer choice. The legislature has not expanded the commission's statutory authority with regards to net metering since the issue was considered in Project No. 34890, with the exception of PURA §39.554, which was enacted in the last legislative session and applies only to EPE. Therefore, the commission will not revisit the issue in the current

rulemaking, but in the future will conduct a rulemaking to implement PURA §39.554(e), (f), and (g).

Section 25.217

Subsection (b)(2); Definition of Distributed Renewable Generation Owner

TREIA, IREC, Houston, and Lennar supported the expansion of the definition of DRG owner to include retail electric customers who contract with third parties. Houston opined that the clarification will facilitate personal investment in DRG by retail customers. IREC suggested that the commission should employ a flexible methodology to determine whether a third-party-owned system is properly sized to meet a customer's load and maintain eligibility for the statutory exemption. IREC added that third-party ownership of DG is, at its core, expanding markets. The third-party model expands the market for DG by overcoming the technical barriers to adoption, helps DG developers engage customers who might not have otherwise invest in or install on-site DG, and can help tax-exempt entities such as schools and local government agencies enjoy the available tax benefits through the third-party. IREC commented that school districts and other budget-constrained local agencies may be subject to a fixed annual appropriation for utility expenses and may lack the financial capacity to purchase an on-site system.

EPE proposed clarification to the definition that would make clear that it does not apply in the EPE territory. EPE argued that the proposed rule implements SB 981 (codified in PURA §39.916), which is not applicable to EPE, pursuant to PURA §39.551. TEC argued that this section is not applicable to cooperatives. ETI agreed with EPE in its reply comments and stated that EPE's claim for non-applicability also applies to ETI because PURA §39.452 exempts ETI from Chapter 39, except in very limited circumstances. Therefore, ETI reasoned that PURA §§39.101(b)(3) and 39.916 regarding DRG are not applicable to ETI. ETI suggested that any attempt to expand the applicability of ownership and operation of DRG outside of ERCOT is inconsistent with the legislature's intent, as expressed in the language in the statutory provisions cited by EPE and ETI.

EPE explained that PURA §39.554(a)(2) expressly provides a different and more limited definition of a DRG owner by defining the term "distributed renewable generation owner" as "an owner of a distributed renewable generation that is a retail electric customer." EPE opined that this section is in conflict with the definition in PURA §39.916, which is mirrored in §25.217(b)(2). Therefore, EPE concluded that PURA §39.554 would be the controlling provision and third-party DRG owner would not be able to install and sell DRG in EPE's service territory.

The AEP Companies stated EPE's comments were well taken, and opined that the new definition of a DRG owner under the rule should be limited to areas that are subject to competition. The AEP Companies (namely SWEPCO) stated that, like EPE, it is not subject to PURA §39.916. The AEP Companies argued that there is no authority outside of PURA §39.916 that would empower the commission to impose the proposed definitions of DRG owner in SWEPCO's service territory and permit a third-party to own and operate a DRG facility and make retail sales from that facility without becoming, and being regulated as, an electric utility. The AEP Companies noted that the commission essentially acknowledged this in Project No. 34890 when it declined to expressly authorize third-party ownership under the original language of PURA §39.916 and deferred to the legislature for action. The AEP Companies noted that Chapter 39 of PURA is limited to areas of the state subject to competition. AEP Companies argued that if the legislature had intended for the definition to apply throughout the state it would have amended a provision that applied to all areas of the state.

El Paso, TREIA, Sierra Club, Lennar, and IREC did not agree with EPE. IREC and TREIA stated that EPE's interpretation of PURA §39.554 is unnecessarily restrictive and undermines the clear and unanimous intent of the legislature to allow utility customers to enter into contracts with third-party owners of DRG systems without the burdens of commission regulation. TREIA commented that EPE's claim regarding PURA §39.554 is not obvious on the face of either SB 981 or SB 1910. TREIA continued that any dispute as to the applicability of SB 981 and its implementing rules would be better addressed in the recently filed general rate case, Docket No. 40094, *Application of El Paso Electric Company to Change Rates and Reconcile Fuel Costs*. TREIA commented further that it viewed the language recommended by EPE to go beyond any appropriate clarification based on the comments filed in the rulemaking project. TREIA stressed that EPE's suggested revisions overreach the plain language and the intent of SB 981 by proactively declaring that a DRG owner in EPE's service area must also be a retail electric customer.

El Paso argued that the changes to the definition EPE proposed would inhibit distributed solar generation in the EPE territory in a manner which was not contemplated in SB 981, and which was not addressed in SB 1910. El Paso requested that the commission reject EPE's proposed change and adopt the definition as published.

Lennar argued that the purpose of SB 981 is to set forth the regulatory treatment of DRG owners, regardless of location. Lennar conceded that there is a conflict between the two provisions of PURA, but stated that PURA §39.554 pertains to interconnections that apply to EPE and does not address the issue of who is a third-party DRG owner that is exempt from commission regulation. Lennar concluded that the legislature did not seek to apply SB 981 to only utility distribution systems in areas of the State that are open to competition. To the contrary, it spoke of the need for a "statewide" solution. IREC emphasized that SB 981 creates a general exemption for third-party owned DRG that applies within EPE's service area, even though most of Chapter 39 of PURA does not apply to EPE; the different definitions of "distributed renewable generation owner" found in PURA §39.554 and §39.916 are in irreconcilable conflict with one another and cannot be harmonized; and the conflicting provisions were enacted by legislation in the same session (SB 1910 and SB 981). IREC argued that the "Texas rules of statutory construction require that the intent and language of SB 981 encourages third-party ownership of DRG prevail, as SB 981 was the statute later enacted by the legislature." IREC requested that the commission give SB 981 the full breadth of its intended impact on the DRG market in Texas and clarify that DRG owners may operate within EPE's territory and interconnect to EPE's distribution system.

Lennar requested that the commission address comments of EPE and TEC by including language in the preamble recognizing that the legislature made perfectly clear that new subsection (k) of §39.916 applies throughout the state. Lennar conceded that whether to apply the definition of DRG owners in SB 981 to third parties in every instance when applying 39.916(k), or only when they are outside of the service territory of a cooperative, for example, could have been made clearer if the definition of a DRG owners in PURA §39.554(a) had also been changed. Lennar argued that the laws of this State that guide statutory construction weigh in favor of extending the benefits of SB 981 to all citizens. Moreover, Lennar stated that denying all the benefits of SB 981 to some citizens is tantamount to denying some of the benefits to all citizens, because every citizen of this State benefits from increased deployment of DRG.

Senator Jose Rodriquez, Senator John Carona, and Representative Dee Margo submitted comments to help clarify questions regarding the legislative intent of SB 981 and SB 1910. The legislators stated that the DRG owner provisions of SB 1910 were written with the assistance of EPE and several community stakeholders, including the El Paso Solar Association. Senator Rodriguez, Senator Carona, and Representative Margo explained that SB 1910 was intended to encourage and facilitate development of solar in El Paso County. At no time did they consider that SB 1910 would augment statewide rules that were being passed through SB 981. They fully expected that SB 981's statewide definition of DRG owner would apply to all of Texas, including El Paso. The legislators also noted that during floor debates the possibility of these pieces of legislation being in conflict did not arise. Senator Rodriguez, Senator Carona, and Representative Margo added that when Chairman Carona inquired about any opposition or controversy, neither EPE nor any of the other witnesses testified that they were aware of any issues regarding the DRG owner definitions.

Senator Rodriguez, Senator Carona, and Representative Margo clarified that SB 1910 was designed to address issues related to net metering and encourage expansion of solar installation in El Paso County. They added that this legislation would not have garnered the near unanimous consent it did if it were anticipated that the bill would grant EPE a narrower definition of what comprises a DRG owner than what is granted to other utilities under SB 981. Senator Rodriguez, Senator Carona, and Representative Margo continued that if the DRG owner definition that is applied to EPE is narrower than that which will be applied to the rest of the state, it will have the effect of limiting customer choice and will increase the cost associated with DRG systems, and would result in the exact opposite of Senator Rodriguez's objective in passing SB 1910 and his stated intention when advancing the bill in the legislature.

Senator Rodriguez, Senator Carona, and Representative Margo also clarified that SB 981 was designed to simplify third-party requirements. More specifically, SB 981 clarified that small, relatively net-zero DRG owners were not classified or required to register under rules more appropriate to generators and utilities producing larger quantities of energy. SB 1910 was similarly designed in part to encourage customer-sited, distributed solar generation. The legislators stated it makes no sense for EPE to now attempt to block a customer-financing mechanism that removes the financial risk from end-use customers, reduces customer transaction costs, and dramatically lowers costs for public customers such as the military, counties, cities, schools, churches, and other non-profit customers. They added that to restrict these types of services during these hard economic times and during a severe drought does not make sense, especially when the end result of a solar lease versus a solar power purchase agreement (PPA) is identical - on-site solar generation with solar power consumed by the paying customer.

Senator Rodriguez, Senator Carona, and Representative Margo urged the commission to enforce the single definition of a DRG owner from SB 981 to EPE and other utilities regardless whether they are inside or outside of ERCOT - to do is consistent with sound public policy and would realize the intent of the legislature.

Commission response

The definition of electric utility is contained in PURA §31.002(6) and effectively provides a general rule that the retail sale of electricity is limited to utilities (*i.e.*, electric utilities, municipally owned utilities, and electric cooperatives). Some exceptions to the general rule are contained in the definition, whereas others are located elsewhere. For example, part (J)(iii) of the definition provides an exception: a person that owns or operates in this state a recreational vehicle park that provides metered electric service in accordance with Texas Utilities Code Chapter 184, Subchapter C. Part (H) of the definition contains the exception for REPs, for parts of the state where customer choice exists. However, PURA §31.002(17)'s definition of REP precludes a REP from owning or operating generating assets, except for DRG that is eligible for treatment under PURA §39.916(k). An example of an exception to the general rule that is located outside of PURA is Texas Utilities Code Chapter 184, Subchapter B. That subchapter provides an exception for the owner of an apartment house or mobile home park that meet certain requirements.

The commission originally adopted §25.217 in 2008 in order to implement PURA §39.916, as well as PURA §39.914. At that time, PURA §39.916(a)(2) defined DRG owner as "the owner of distributed renewable generation." In its order adopting new §25.217, the

commission stated: "The commission declines to address at this time whether a person other than the end-use customer may own DRGO or ISD-SG [independent school district solar generation, which is addressed in PURA §39.914]. Having third parties own DRG and ISD-SG may have a number of benefits, including tax benefits and economies of scale. *However, it is unclear whether a third party could own the facilities without becoming an electric utility, with all the associated duties and responsibilities, and the commission will refer the matter for legislative consideration* in its Scope of Competition in Electric Markets in Texas report to the 81st Texas Legislature." ***See PUC Rulemaking Relating to Net Metering and Interconnection of Distributed Generation,* Project 34890, Order (December 22, 2008) (emphasis added).**

The commission did include in its scope report to the 81st Legislature a suggestion that the Legislature amend PURA to address third-party ownership of DRG. *See* Report to the 81st Texas Legislature: Scope of Competition in Electric Markets in Texas (January 2009) at 82. The 81st Legislature did not take action on this issue, so the commission again addressed the issue in its scope of competition report to the 82nd Legislature: "In the 2007 session of the Legislature, two new sections were added to PURA to address issues related to distributed renewable generation (DRG), including solar generation. It appears that the Legislature expected that these new sections would foster additional renewable capacity that would be installed at customers' homes and businesses, including solar generation on the buildings of school districts. There remain provisions of PURA that may create obstacles to the installation of DRG, particularly where a person other than the owner of the home or business would own or operate the DRG. The commission recently created a new type of REP that would be authorized to sell energy from a DRG to the business on whose property the DRG is located.

This development may result in the installation of more DRG facilities for larger, nonresidential customers. If the recent change is successful, the commission could consider applying the same rules to third-party ownership of DRG at residential premises, too. Ownership of the DRG by a third party could provide economies of scale or tax benefits to the third-party owner of the DRG that would not be otherwise available to the customer. *Another option for fostering DRG would be to amend PURA to remove the obstacles to third-party ownership of DRG for all customers*." ***See* Report to the 82nd Texas Legislature: Scope of Competition in Electric Markets in Texas (January 2011) at 92 (emphasis added).**

Senate Bill 981, enacted by the 82nd Legislature, addressed DRG ownership and other obstacles to the installation of DRG. The House bill analysis for SB 981 stated: "Interested parties consider distributed generation to be electricity produced on-site and connected to a utility distribution system and contend that there is a need for classification of distributed generation in state policy as technological advances have made such generation more affordable and desirable. The parties contend that statute is unclear with regard to small-scale distributed generators and does not adequately address whether such generators are required to register with the Public Utility Commission of Texas. C.S.S.B. 981 seeks to clarify such issues by establishing provisions relating to the regulation of distributed renewable generation of electricity." ***See* House Comm. on State Affairs, Bill Analysis, C.S.S.B. 981, 82nd Leg., R.S. (2011).**

Both Senate bill analyses stated that "Recent technological advances make distributed generation more affordable and desirable than ever before, but statewide policies do not exist for classification of distributed generation." ***See*** **Senate Business & Commerce Committee, Bill Analysis, C.S.S.B. 981, 82nd Leg., R.S. (2011) and Senate Business & Commerce Committee, Bill Analysis, S.B. 981, 82nd Leg., R.S. (2011).**

SB 981 amended PURA §39.916 to change the definition of DRG owner and address licensing requirements related to certain DRG:

SECTION 1. Subdivision (2), Subsection (a), Section 39.916, Utilities Code, is amended to read as follows:

(2) "Distributed renewable generation owner" means:

(A) an [~~the~~] owner of distributed renewable generation;

(B) a retail electric customer on whose side of the meter distributed renewable generation is installed and operated, regardless of whether the customer takes ownership of the distributed renewable generation; or

(C) a person who by contract is assigned ownership rights to energy produced from distributed renewable generation located at the premises of the customer on the customer's side of the meter.

SECTION 2. Section 39.916, Utilities Code, is amended by adding Subsection (k) to read as follows:

(k) Neither a retail electric customer that uses distributed renewable generation nor the owner of the distributed renewable generation that the retail electric customer uses is an electric utility, power generation company, or retail electric provider for the purposes of this title and neither is required to register with or be certified by

<u>the commission if at the time distributed renewable generation is installed, the estimated annual amount of electricity to be produced by the distributed renewable generation is less than or equal to the retail electric customer's estimated annual electricity consumption.</u>

The purpose of SB 981 was the elimination of obstacles to use of DRG, with the bill enacted by the Legislature without any vote against it. SB 981 creates a new exception to the definition of electric utility for an owner of DRG, so long as the DRG meets the requirements of PURA §39.916(k), which requires the amount of electricity produced by the DRG to be less than or equal to the retail electric customer's estimated annual electricity consumption. Subsection (k) exempts qualifying DRG from licensing requirements "for purposes of this title," meaning the entirety of PURA. The Legislature's manifest intent was to establish a statewide policy for DRG ownership. It is important to note that subsection (k) addresses customers and owners of DRG, not electric utilities. Because subsection (k) applies to customers and owners of DRG "for the purposes of" PURA, it applies in all electric utility service areas. Subsection (k)'s application is not eliminated in an electric utility service area by other provisions of PURA that exempt certain electric utilities from PURA §39.916.

There are five electric utilities providing retail service in areas in which customer choice does not currently exist: Sharyland Utilities, L.P.; EPE; SPS; ETI; and SWEPCO. These electric utilities are addressed below.

Customer choice has not yet been implemented for the following divisions of Sharyland: Stanton, Colorado City, Brady, and Celeste. For these divisions, there is no facial conflict in PURA as to the applicability of PURA §39.914 and §39.916. PURA §39.102(d) applies to these divisions. In applying §25.217 to these Sharyland divisions, the commission is exercising its authority, pursuant to PURA §39.102(d), to "oversee the compliance" with PURA Chapter 39 by Sharyland.

PURA §39.552(b) provides that until the date on which customer choice is implemented in EPE's service area, the provisions of PURA Chapter 39, other than Subchapter L, §39.904, and §39.905, do not apply to EPE. Subchapter L includes PURA §39.554, which addresses DRG. Provisions in PURA §39.554 differ from PURA §39.916. For example, PURA §39.554(e) provides a DRG owner a metering option that is not listed in PURA §39.916(f) and §25.213 of this title (relating to Metering for Distributed Renewable Generation). Therefore, as stated above with respect to comments about net metering, in the future the commission will conduct a rulemaking to implement PURA §39.554. Until that time, §25.217 will apply to EPE in light of PURA §39.554, and where conflicts exist, PURA §39.554 will control.

With respect to DRG owners, subsection (k) of PURA §39.916 controls for EPE over the definition in PURA §39.554(a)(2) to the extent they conflict, because subsection (k) of PURA §39.916 applies "for the purposes of" PURA. In addition, subsection (k) of PURA §39.916 was enacted after §39.554 was enacted by the Legislature and the bill in which it was enacted, SB 981, is special to DRG, whereas the bill that enacted §39.554 was not

special to DRG. In addition, as discussed previously, the manifest intent of the Legislature in adopting SB 981 was to establish a statewide policy on DRG ownership.

The purpose of the inclusion of PURA §39.554 in SB 1910 was to promote DRG in EPE's service area. Only two days before enacting SB 981, the Legislature enacted Senate Bill 1910 with only one vote against it. Senator Rodriguez, the author of SB 1910; Representative Margo, a sponsor of SB 1910; and Senator Carona, the author of SB 981, filed comments in this rulemaking confirming that they intended that PURA §39.916(k) apply to EPE.

The remaining electric utilities in whose service areas customer choice does not currently exist are SPS, ETI, and SWEPCO. PURA Chapter 39, Subchapter I applies to SPS, and PURA §39.402(a) in that subchapter states that until the date on which customer choice is implemented in its service area, the provisions of PURA Chapter 39, other than Subchapter I, §39.904, §39.905, and certain environmental provisions, do not apply to SPS. PURA Chapter 39, Subchapter J applies to ETI, and PURA §39.452(d)(1) in that subchapter states that until the date on which customer choice is implemented in its service area, the provisions of PURA Chapter 39, other than Subchapter J, §39.904, §39.905, and certain environmental and cost recovery provisions, do not apply to ETI. PURA Chapter 39, Subchapter K applies to SWEPCO, and PURA §39.502(b) in that subchapter provides that until the date on which customer choice is implemented in its service area, the provisions of PURA Chapter 39, other than Subchapter K, §39.904, and §39.905, do not apply to SWEPCO. However, as explained above, subsection (k) of PURA §39.916 applies

in all electric utility service areas, and does not vary depending on whether customer choice exists in an electric utility's service area.

Although PURA §39.914 and §39.916 other than subsection (k) do not apply to SPS, ETI, and SWEPCO, in originally adopting §25.217, the commission made §25.217 applicable to these electric utilities based on its authority outside of PURA Chapter 39. *See Rulemaking Proceeding Relating to Net Metering and Interconnection of Distributed Generation*, Project No. 34890, Order (December 22, 2008) at 4-5. Apart from comments on the applicability of the new definition of DRG owner, no commenter suggested changing §25.217 so that it would not apply to SPS, ETI, and SWEPCO. Furthermore, nothing has changed since the original adoption of §25.217 that warrants discontinuing its application to these electric utilities.

As stated previously in response to comments on proposed §25.217(b), it is in the public interest to allow customers to have DG, including DRG, and PURA provisions outside of PURA Chapter 39 give the commission the authority to allow it. These provisions include PURA §14.001, which states: "The commission has the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by this title that is necessary and convenient to the exercise of that power and jurisdiction." **PURA §35.061 requires the commission to adopt and enforce rules to encourage the economical production of electric energy by qualifying facilities, and DRG are eligible to be certified by FERC as qualifying facilities. In addition, PURA §36.001 gives the commission the authority to establish and regulate rates of electric**

utilities. ***See*** **PURA §31.002(15) (defining "rate" broadly). PURA §38.002 authorizes the commission to adopt standards relating to measurement, quality of service, and metering standards. Therefore, §25.217, as amended herein, continues to apply to all electric utilities (except river authorities).**

Subsection (i); Exemptions

Houston supported the addition of a provision which specifies that an electric customer who uses or owns small-scale DRG is not classified as an electric utility, power generation company, or retail electric provider and is not required to register with the commission. Houston added that this clarification in this subsection is consistent with SB 981 and will facilitate DRG investment by retail customers.

IREC urged the commission to adopt flexible standards for determining whether a customer-sited DG system is sized "less than or equal to the retail electric customer's estimated annual electricity demand." IREC suggested that the commission adopt a permissive approach to the load-sizing criteria. IREC explained that while it is clear that the legislature intended a limiting principle behind the exemption, it is not entirely clear or intuitive what is meant by a customer's estimated annual electricity consumption. IREC opined that the commission has broad discretion to establish the proper parameters for a customer to "estimate annual usage."

IREC also noted that the statute does not give the commission a mandate to certify that a DG facility is compliant with this subsection and therefore qualifies for the exemption. Rather, IREC argued, the statute specifically insists that a DG owner or host customer "is not an electric utility, power generation company, or retail electric provider…and is not required to register with or be certified by the commission," so long as the system is designed to meet estimated annual load at the time of installation. IREC concluded that the statue takes a "hands off" approach to allow third-party owners and host customers to properly size a system to match the customer's needs.

IREC recommended that "the [c]omission should employ a flexible methodology to determine whether a third-party owned system is properly sized to meet a customer's load and maintain eligibility for the statutory exemption." The rule should include an error tolerance in any methodology it adopts to determine whether a system was properly sized at the time of installation. IREC noted an example of such a flexible standard is found in Pennsylvania. In reply comments, the REP Coalition responded that it believed that the allowed use of estimates of annual consumption and annual output in the calculation already provides such flexibility without the need for further qualification. The REP Coalition stated that the IREC's proposed amendment is unnecessary.

Commission response

The commission agrees with the REP Coalition that the proposed language, which mirrors PURA §39.916, provides flexibility in the use of estimates for annual consumption and annual production. The commission does not believe that further clarification in this rule is necessary. Therefore, the commission declines to make IREC's suggested changes.

The amendments are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (West 2007 and Supp. 2011) (PURA), which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; and specifically, PURA §14.001, which gives the commission the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by this title that is necessary and convenient to the exercise of that power and jurisdiction; PURA §31.002(4-a), which defines distributed natural gas generation facility; §31.002(20), which defines transmission service to include construction or enlargement of facilities and transmission over distribution facilities; §§35.001-35.007, which give the commission authority over the provision of wholesale transmission service by an electric utility, including an electric cooperative; §35.036, which addresses a distributed natural gas generation facility's interconnection to, and use of, the transmission and distribution facilities of an electric utility or electric cooperative; §35.061, which requires the commission to adopt and enforce rules to encourage the economical production of electric energy by qualifying facilities; §38.002, which authorizes the commission to adopt standards relating to measurement, quality of service, and metering standards; §36.001, which gives the commission the authority to establish and regulate rates of electric utilities; §39.101(b)(3), which entitles a customer to have access to on-site DG; §39.203(b), which requires an electric utility or an electric cooperative that has not opted for customer choice to provide wholesale transmission service at distribution voltage when necessary to serve a wholesale customer; §39.351, which requires that a power generation company be registered with the commission; and §39.916, which addresses DRG.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.001, 14.002, 31.002(20), 35.001-35.007, 35.036, 35.061, 36.001, 38.002, 39.101(b)(3), 39.203(b), 39.351, and 39.916.

§25.211. Interconnection of On-Site Distributed Generation (DG).

(a) **Application.** Unless the context indicates otherwise, this section and §25.212 of this title (relating to Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation) apply to an electric utility for all purposes except to the extent preempted by federal law. The only part of this section that applies to electric cooperatives is subsection (o) of this section.

(b) **Purpose.** The purpose of this section includes stating the terms and conditions that govern the interconnection and parallel operation of both on-site distributed generation in order to implement Public Utility Regulatory Act (PURA) §39.101(b)(3) and a natural gas distributed generation facility in order to implement PURA §35.036. Sales of power by on-site distributed generation and natural gas distributed generation 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).

(c) **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 for interconnection and parallel operation with the utility system or application--** he standard form of application approved by the commission.

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

(3) **Customer--**Any entity interconnected to the company's utility system for the purpose of receiving or exporting electric power from or to the company's utility system.

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

(5) **Facility**-- n electrical generating installation consisting of one or more on-site distributed generation units, including a distributed natural gas generation facility. The total capacity of the installation's on-site distributed generation units may exceed ten megawatts (MW); however, no more than ten MW of the installation's capacity will be interconnected at any point in time at the point of common coupling under this section.

(6) **Interconnection--**The physical connection of distributed generation to the utility system in accordance with the requirements of this section so that parallel operation can occur.

(7) **Interconnection agreement--**The standard form of agreement, which has been approved by the commission. The interconnection agreement sets forth the contractual conditions under which a company and a customer agree that one or more facilities may be interconnected with the company's utility system.

(8) **Inverter-based protective function--**A function of an inverter system, carried out using hardware and software, that is designed to prevent unsafe operating conditions from occurring before, during, and after the interconnection of an inverter-based static power converter unit with a utility 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 utility system.

(9) **Network service--**Network service 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. The service is designed to maintain service to the customers even after the loss of one of these primary distribution feeder sources.

(10) **On-site distributed generation (or distributed generation)--**An electrical generating facility located at a customer's point of delivery (point of common coupling) of ten megawatts (MW) or less and connected at a voltage less than 60 kilovolts (kV) which may be connected in parallel operation to the utility system.

(11) **Parallel operation--**The operation of on-site distributed generation while the customer is connected to the company's utility system.

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

(13) **Pre-certified equipment**-- specific generating and protective equipment system or systems that have been certified as meeting the applicable parts of this section relating to safety and reliability by an entity approved by the commission.

(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 utility system impact studies.

(15) **Stabilized--** 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 two minutes or a shorter time as mutually agreed to by the company and customer.

(16) **Tariff for interconnection and parallel operation of distributed generation--** The commission-approved tariff for interconnection and parallel operation of distributed generation including the application for interconnection and parallel operation of distributed generation and pre-interconnection study fee schedule.

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

(18) **Utility system**--A company's distribution system below 60 kV to which the generation equipment is interconnected.

(d) **Terms of Service.**

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

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

(3) **Transmission charges.** No transmission charges shall 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) **Contract reformation.** All interconnection contracts shall be conformed to meet the requirements of this section within 60 days of adoption.

(5) **Tariffs.** No later than 30 days after the effective date of this section as amended, each electric utility shall file a tariff or tariffs for interconnection and parallel operation of distributed generation in conformance with the provisions of this section. This provision does not require a utility that filed an interconnection study fee tariff prior to the effective date of this rule as amended to refile such tariff. The utility may file a new tariff or a modification of an existing tariff. Such tariffs shall ensure that back-up, supplemental, and maintenance power is available to all customers and customer classes that desire such service, if the electric utility sells electricity. Any modifications of existing tariffs or offerings of new tariffs relating to this subsection shall be consistent with the commission-approved form. Concurrent with the tariff filing in this section, each utility shall submit:

(A) a schedule detailing the charges of interconnection studies and all supporting cost data for the charges;

(B) a standard application for interconnection and parallel operation of distributed generation; and

(C) the interconnection agreement approved by the commission.

(e) **Disconnection and reconnection.** A utility may disconnect a distributed generation unit from the utility system under the following conditions:

(1) **Expiration or termination of interconnection agreement.** The interconnection agreement specifies the effective term and termination rights of company 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 generation 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 facility without prior written notice in cases where continued interconnection will endanger persons or property. During the forced outage of a utility system, the utility shall have the right to temporarily disconnect a customer's facility to make immediate repairs on the utility's 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 or a customer's facility with seven business days prior written notice of a service interruption for routine maintenance, repairs, and utility system modifications. The utility shall 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 distributed generation to a utility system, a customer must first submit to the utility an application for interconnection and parallel operation with the utility system and execute an interconnection agreement on the forms prescribed by the commission. The utility may refuse to connect or may disconnect the customer's facility if such application has not been received and approved.

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

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

(1) **Distributed generation 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 pre-certified distributed generation units up to 500 kW 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) **Distributed generation facilities for which pre-interconnection study fees may be charged.** Prior to the interconnection of a distributed generation facility not described in paragraph (1) of this subsection, a utility may charge a customer a fee to offset its costs incurred in the conduct of a pre-interconnection study. In those instances where a utility conducts an interconnection study the following shall apply:

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

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

(C) The study shall consider both the costs incurred and the benefits realized as a result of the interconnection of distributed generation to the company's utility system; and

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

(h) **Network interconnection of distributed generation.** Certain aspects of secondary network systems create technical difficulties that may make interconnection more costly to implement. In instances where customers request interconnection to a secondary network system, the utility and the customer shall use best reasonable efforts to complete the interconnection and the utility shall utilize the following guidelines:

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

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

(3) A utility may postpone processing an application for an individual distributed generation facility under this section if the total existing distributed generation on the targeted feeder represents more than 25% of the total load of the secondary network under consideration. If that is the case, the utility should conduct interconnection and network studies to determine whether, and in what amount, additional distributed generation facilities can be safely added to the feeder or

accommodated in some other fashion. These studies should be completed within six weeks, and application processing should then resume.

(4) A utility may reject applications for a distributed generation facility under this section if the utility can demonstrate specific reliability or safety reasons why the distributed generation should not be interconnected at the requested site. However, in such cases the utility shall work with the customer to attempt to resolve such problems to their mutual satisfaction.

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

(i) **Pre-Interconnection studies for network interconnection of distributed generation.** Prior to charging a pre-interconnection study fee for a network interconnection of distributed generation, a utility shall first advise the customer of the potential problems associated with interconnection of distributed generation with its network system. For potential interconnections to network systems there shall be no pre-interconnection study fee assessed for a facility with inverter systems under 20 kW. 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 more than four weeks;

(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 distributed generation to the utility's system; and

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

(j) **Communications concerning proposed distributed generation projects.** In the course of processing applications for interconnection and parallel operation and in the conduct of pre-interconnection studies, customers shall provide the utility detailed information concerning proposed distributed generation facilities. Such communications concerning the nature of proposed distributed generation facilities shall be made 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 generation 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 generation, or offer competing distributed generation projects.

(k) **Equipment pre-certification.**

(1) **Entities performing pre-certification.** The commission may approve one or more entities that shall pre-certify equipment as defined pursuant to this section.

(2) **Standards for entities performing pre-certification.** Testing organizations and/or facilities capable of analyzing the function, control, and protective systems of distributed generation units may request to be certified as testing organizations.

(3) **Effect of pre-certification.** Distributed generation units which are certified to be in compliance by an approved testing facility or organization as described in this subsection shall be installed on a company utility system in accordance with an approved interconnection control and protection scheme without further review of their design by the utility.

(l) **Designation of utility contact persons for matters relating to distributed generation interconnection.**

(1) Each electric utility shall designate a person or persons who will serve as the utility's contact for all matters related to distributed generation interconnection.

(2) Each electric utility shall identify to the commission its distributed generation 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 distributed generation contact person.

(m) **Time periods for processing applications for interconnection with the utility system.** In order to apply for interconnection the customer shall provide the utility a completed application for interconnection and parallel operation with the utility system. The interconnection of distributed generation to the utility system shall take place within the following schedule:

(1) For a facility with pre-certified equipment, interconnection shall take place within four weeks of the utility's receipt of a completed interconnection application.

(2) For other facilities, interconnection shall take place within six weeks of the utility's receipt of a completed application.

(3) If interconnection of a particular facility will require substantial capital upgrades to the utility system, the company shall provide the customer an estimate of the schedule and customer's cost for the upgrade. If the customer desires to proceed with the upgrade, the customer and the company will enter into a contract for the completion of the upgrade. The interconnection shall take place no later than two weeks following the completion of such upgrades. The utility shall employ best reasonable efforts to complete such system upgrades in the shortest time reasonably practical.

(4) A utility shall use best reasonable efforts to interconnect facilities within the time frames described in this subsection. If in a particular instance, a utility determines that it cannot interconnect a facility within the time frames stated in this subsection, it 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.

(5) All applications for interconnection and parallel operation of distributed generation shall be processed by the utility in a non-discriminatory manner. Applications will 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.

(n) **Reporting requirements.** Each electric utility shall maintain records concerning applications received for interconnection and parallel operation of distributed generation. Such records will include the name of the applicant, the business address of the applicant, and the location of the proposed facility by county, the capacity rating of the facility in kilowatts, whether the facility is a renewable energy resource as defined in §25.173 of this title (relating to Goal for Renewable Energy), the date each 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 distributed generation 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 March 30 of each year, every electric utility shall file with the commission a distributed generation interconnection report for the preceding calendar year that identifies each distributed generation facility interconnected with the utility's distribution system. The report shall list the new distributed generation 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 utility 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.

(o) **Distributed natural gas generation facility**. This subsection, as well as the other subsections of this section, apply to a distributed natural gas generation facility. 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.

§25.217. Distributed Renewable Generation.

(a) **Application**. This section applies to owners of distributed renewable generation, retail electric providers (REPs), the program administrator for the renewable energy credits trading program pursuant to §25.173 of this title (relating to Goal for Renewable Energy), and electric utilities, including transmission and distribution utilities (TDUs), but excludes river authorities that are electric utilities.

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

(1) **Distributed renewable generation (DRG)** -- Electric generation equipment with a capacity of not more than 2,000 kilowatts provided by a renewable energy technology, as defined by Public Utility Regulatory Act §39.904(d), installed on a retail electric customer's side of the meter.

(2) **Distributed renewable generation owner (DRGO)** -- A person who owns DRG; a retail electric customer on whose side of the meter DRG is installed and operated, regardless of whether the customer takes ownership of the distributed renewable generation; or a person who by contract is assigned ownership rights to energy produced from DRG located at the premises of the customer on the customer's side of the meter.

(3) **Independent school district solar generation (ISD-SG)** -- Solar electric generation equipment installed on the customer's side of the meter at a building

or other facility owned or operated by an independent school district, irrespective of the level of generation capacity.

(4) **Independent school district solar generation owner (ISD-SG Owner)** -- A person who owns ISD-SG.

(5) **Interconnection** -- The physical connection of DRG or ISD-SG to an electric utility distribution system in accordance with this section and §25.211 of this title (relating to Interconnection of On-Site Distributed Generation (DG)), §25.212 of this title (relating to Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation), and §25.213 of this title (relating to Metering for Distributed Renewable Generation).

(6) **Out-flow** - Energy produced by DRG or ISD-SG and delivered to an electric utility distribution system.

(c) **Interconnection**.

(1) An electric utility shall permit interconnection of DRG or ISD-SG if:

(A) the DRGO provides credible tangible proof that the DRG to be interconnected has or had an original manufacturer's warranty against breakdown or undue degradation for at least five years;

(B) the rated capacity of the DRG or ISD-SG does not exceed the electric utility's service capacity; and

(C) the DRG or ISD-SG is in compliance with applicable requirements of §25.211 and §25.212 of this title.

(2) An electric utility may disconnect a DRG or ISD-SG pursuant to §25.211(e) of this title.

(3) An electric utility shall not require a DRGO or ISD-SG Owner whose generation capacity is not more than 2,000 kilowatts and whose DRG or ISD-SG meets the standards established by this section to purchase an amount, type, or classification of liability insurance the DRGO or ISD-SG Owner would not have in the absence of the DRG or ISD-SG.

(4) An existing or prospective DRGO or ISD-SG Owner may request interconnection by submitting an application for interconnection with the electric utility. The application shall be on a form approved by the commission and processed by the electric utility in accordance with §25.211 and §25.212 of this title.

(5) Metering is addressed by §25.213 of this title and, for certain qualifying facilities, by §25.242(h)(4) of this title (relating to Arrangements Between Qualifying Facilities and Electric Utilities).

(d) **Renewable Energy Credits (RECs)**. A DRGO or ISD-SG is subject to the certification requirements in §25.173 of this title to be eligible to receive RECs. Any RECs or compliance premiums resulting from the operation of DRG or ISD-SG are the property of the DRGO or ISD-SG Owner unless sold or otherwise transferred by the DRGO or ISD-SG Owner. The REC program administrator shall award the RECs or compliance premiums to the DRGO or ISD-SG Owner pursuant to §25.173 of this title. The purchase of out-flows does not automatically confer any rights of REC ownership on the purchaser.

(e) **Sale of out-flows by an ISD-SG Owner**.

(1) In areas of the state in which customer choice has not been introduced, the electric utility serving the load of an ISD-SG Owner shall buy all ISD-SG out-flows at a value consistent with §25.242 of this title.

(2) In areas in which customer choice has been introduced, ISD-SG Owners who choose to sell out-flows shall sell out-flows to the REP that serves the premises at which the ISD-SG is located, at a value to which both parties agree.

(3) If a REP's service to an ISD-SG Owner is terminated, any outstanding amounts due to the ISD-SG Owner may be used to offset outstanding bill amounts but in all cases shall be remitted by the REP no later than 30 days after the REP receives the usage data and any related invoices for non-bypassable charges.

(f) **Sale of out-flows by a DRGO**.

(1) In areas in which customer choice has not been introduced, the electric utility serving the DRGO's load shall buy all DRG out-flows at a value consistent with the requirements of §25.242 of this title.

(2) In areas in which customer choice has been introduced, DRGOs who choose to sell out-flows shall sell their out-flows to the REP that serves the premises at which the DRG is located at a value to which both parties agree.

(3) If a REP's service to a DRGO is terminated, any outstanding amounts due to the DRGO may be used to offset outstanding bill amounts but in all cases shall be

remitted by the REP no later than 30 days after the REP receives the usage data and any related invoices for nonbypassable charges.

(g) **Transition provision.** Electric utilities and REPs shall make reasonable efforts to inform existing and potential DRGOs and ISD-SG Owners of their rights and obligations pursuant to this chapter, and shall change existing metering and purchase arrangements to conform to this section. However, a metering or purchase arrangement that is required by a contract that exists on the effective date of this section shall be changed to conform to this section effective the date the contract expires. The expiration date of such a contract may be extended by the DRGO or ISD-SG Owner if the existing terms of the contract give the DRGO or ISD-SG Owner the unilateral right to extend the expiration date. Notwithstanding the foregoing provisions of this subsection, a roll-back meter must be replaced no later than the date customer choice is offered in the area in which the roll-back meter is located.

(h) **Authority to act on behalf of a customer**. If any person purports to act on behalf of the retail customer pursuant to this section or §§25.211, 25.212 or 25.213 of this title, such person must demonstrate contractual authority to do so by letter of agency or otherwise.

(i) **Exemptions**. Neither a retail electric customer that uses distributed renewable generation nor the owner of the distributed renewable generation that the retail electric customer uses is an electric utility, power generation company, or retail electric provider for the purposes of this chapter and is not required to register with or be certified by the commission if at the time distributed renewable generation is installed, the estimated annual amount of electricity to be produced by the distributed renewable generation is less than or equal to the retail electric customer's estimated annual electricity consumption.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that §25.211 relating to Interconnection of On-Site Distributed Generation (DG) is hereby adopted with changes to the text as proposed and §25.217 relating to Distributed Renewable Generation is hereby adopted without changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE ___22nd__ DAY OF MAY 2012.

PUBLIC UTILITY COMMISSION OF TEXAS

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DONNA L. NELSON, CHAIRMAN

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KENNETH W. ANDERSON, JR., COMMISSIONER

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ROLANDO PABLOS, COMMISSIONER

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