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 as published in the October 6, 2000 *Texas Register* (25 TexReg 10080). The amendments are necessary to establish reasonable scheduling fees for DG and remove other economic barriers to DG. The amendments: (1) require any utility that owns and operates a distribution system that is not subject to imbalance fees for wholesale transactions to provide banking services to operators of distributed generation facilities until the Electric Reliability Council of Texas (ERCOT) Independent System Operator (ISO) begins operating ERCOT as a single control area; (2) prohibit collection of distribution-related charges from an exporting customer; and (3) prohibit collection of transmission-related charges from an exporting customer. The amendments also define the term "banking" and change the reference to the "Office of Regulatory Affairs" in subsection (o) to the "Electric Division" to reflect a recent organizational change. Project Number 22540 has been assigned to this proceeding.

The commission received comments on the proposed amendment from American Electric Power (AEP), Energy Developments, Inc. (EDI), Entergy Gulf States, Inc. (EGSI), Reliant Energy (Reliant), Small Hydro of Texas, Inc. (SHOT), Southwest Public Service Company (SPS), and TXU Electric Company (TXU).

The commission solicited comments on a series of questions posed in the proposed rules. The comments on those questions as well as proposed revisions to the rule, and the commission's responses thereto, are summarized below.

1. Do technical complications arise from installation of significant amounts of distributed generation on a feeder? If so, please describe the nature of these complications, with specificity on both the magnitude of DG installation relative to feeder load and the potential impacts, and possible solutions.

Four utilities, AEP, EGSI, Reliant, and TXU commented that significant amounts of DG on a feeder can cause both safety and reliability problems.

EGSI did not discuss specific problems that could arise from large amounts of DG on a feeder, but noted that complications could be expected to vary with the magnitude of the DG, the magnitude and character of loads on the same distribution circuit and on other distribution circuits served from the same or adjacent substations, and the character and capabilities of the distribution and transmission systems serving a DG facility.

AEP discussed a number of specific problems that it believes can arise from installation of large amounts of DG on a feeder. AEP argued that the potential resolution of the specific problems identified by AEP is in the actual interconnection of DG. DG customers should be required to comply with the requirements of existing commission rules. A distribution feeder with more generation than load is not a distribution feeder from a practical standpoint. The most economical way to accommodate large amounts of DG would be through use of dedicated lines and dedicated substations. This would remove the load that is distributed along the line and the protection schemes could be designed for the operation of DG as a priority. This would give the DG a greater chance of being able to respond to system needs appropriately instead of being shed from the system.

Reliant indicated that installation of significant amounts of DG on a feeder could endanger public safety, reliability, and power quality. Each feeder has inherent limitations on the amount of power it can support. The impact of each DG facility depends upon the particular limitations of the feeder. Therefore specific magnitudes of DG installations cannot be addressed without the use of interconnection studies. Reliant also addressed specific potential problems associated with significant amounts of DG on a feeder, as summarized below.

TXU commented that as the aggregate amount of DG connected to a feeder approaches the ten megawatt (MW) capacity limit of a feeder, the probability of technical complications that can affect reliability and safety also increases. In general, as long as the total amount of DG connected to a feeder does not exceed the ten MW capacity limit of the feeder, there are solutions to these problems that are not excessively costly because the ten MW limit corresponds to the maximum load rating of a typical 12 kilovolt (kV) distribution feeder. TXU also addressed specific potential problems associated with significant amounts of DG on a feeder.

AEP and Reliant commented that restoration of service on a feeder with multiple DG facilities will be complicated and take more time because of the need to isolate the DG facilities to prevent backfeed. Manual switching may be required to reroute the DG on the feeder if the output from the DG facility is necessary to serve load on the feeder. AEP was concerned about how this potential increase in service restoration times will impact its ability to comply with commission requirements for feeder reliability. Reliant recommended that this problem be remedied by installation of remotely controlled switches at the DG sites so that these units can be disconnected from the feeder without the necessity of personnel going to each individual DG site for both disconnection and reconnection.

AEP, Reliant, and TXU commented that the presence of DG on a feeder impacts available fault current. With multiple DG facilities, the fault current at various points on the feeder can vary greatly depending on the location and status of the DG on the feeders. If the available fault current is stable, the system can be designed to operate properly. However, where DG is present, the fault current level will vary with the status of the DG. In some cases, this varying available fault current could lead to protective device miscoordination and lower feeder reliability. The increase in potential fault current due to increases in connected DG facilities may also exceed the fault interrupting capability of various devices connected to the line, including customer-owned equipment, resulting in damage of connected equipment. Reliant suggested that this problem could be remedied through upgrades of underrated equipment identified during the interconnection study.

AEP stated that voltage flicker may increase with increasing DG on a feeder. Voltage flicker is a function of the frequency of occurrence and the magnitude of voltage fluctuation. While individual DG units may meet voltage flicker limitations, the combined voltage flicker from multiple DG units and other flicker-producing loads may create objectionable levels of flicker on the feeder.

AEP and TXU commented that DG on a feeder can increase the chances of the feeder operating in an island mode when the feeder breaker or other sectionalizing device has opened. A relatively small amount of generation connected to a large load will quickly decay outside allowable limits of frequency and voltage and be disconnected by relays. If the feeder has generation sufficient to support the load, it may continue to operate resulting in an island which could create safety problems. TXU suggested that hazards associated with this potential problem could be remedied by changing operating procedures and installing additional coordination equipment.

AEP, Reliant, and TXU commented that the presence of DG will affect the load flow on a feeder and hence the voltage profile. Varying the amount of DG on a feeder can create voltage regulation problems due to the higher feeder voltage profile variation. With multiple DG facilities, the potential combinations of feeder conditions may be extremely complicated to model. Reliant suggested that this potential problem could be remedied by giving the transmission and distribution utility (TDU) the ability to control all DG volt/var output through System Control and Data Acquisition (SCADA).

AEP and Reliant commented that the presence of DG on a feeder will generally affect reactive power flow. Multiple DG facilities on a feeder could create reactive support problems. To remedy this problem, special filtering and/or switching control schemes may be required. AEP recommended that DG interconnections be subject to §25.51 regarding power quality concerns.

AEP commented that planning the appropriate capacity of distribution facilities will have an added variable when significant DG is added. With some loads served on a daily basis by DG, the ability to plan for handling load requirements under different operational conditions becomes more difficult because the load displaced by DG may become hidden to the distribution planner. This load may then reappear on the system if the DG is taken out of service, either temporarily or permanently. To the extent the distribution planner relied on the DG, distribution infrastructure may be unable to support load if DG is not available. TXU commented that multiple exporting DG facilities of significant size on a feeder would increase the likelihood that the electrical current flow in any particular section of the feeder will change direction depending upon which DG facilities are operating at a particular point in time. When this situation occurs, the feeder becomes a mini-network of different electrical sources. Both utilities suggested that, to respond to a large penetration of DG within its systems, a distribution utility would have to develop new methods and tools to analyze the impact of DG. In addition, staffing levels may have to be increased to properly plan for an increasingly complex system.

AEP commented that large amounts of DG can create the potential for negative impacts on the bulk power system. These impacts can occur in the area of frequency response and reactive response. DG complicates the process of determining the amount of generation needed to respond to a loss of generation. Significant DG penetration may require the operation of DG consistent with the Operating Protocols being developed for the ERCOT ISO. Use of the ERCOT Protocols should help avoid biasing the data that operators use to determine responsive reserve levels. The cumulative effects of system disturbances on a number of feeders would likely significantly impact the ability of the system to recover from a sudden loss of generation.

AEP also commented that a separate but similar system impact could also affect the system's ability to maintain voltage support during disturbances. Just as real power is needed for the system when a large generator trips off, reactive power (vars) is needed during system disturbances that create a voltage drop. This deficiency can be localized and can be the result of a major transmission line tripping off as well as a generator or a large reactive source such as a shunt capacitor. The over and under voltage relays would disconnect the DG units from the line resulting in a loss of an important source of real and reactive power which could in turn lead to a major system outage.

Reliant commented that a significant amount of DG on a feeder may keep the feeder energized after a short circuit has occurred. As a result, the only power flowing on the feeder would be from the DG, subjecting the feeder to abnormal voltage and frequency levels. Equipment located on the feeder that is not owned by the DG may be susceptible to damage or malfunction. Reliant suggested that to remedy this problem, the TDU should install transfer trips on all DG units when the aggregate amount of DG on a feeder exceeds 50% of minimum peak load to prevent DG power flow onto the feeder when a breaker trips.

Reliant commented that significant amounts of DG can cause unnecessary operation of additional TDU protective devices. TDU protective devices have been coordinated for radial flow, not the type of backfeed that can occur when a DG unit is located on a feeder. If power flows from the DG to a short circuit, some protective equipment on the feeder might be exposed to current levels not normally experienced. This would cause protective equipment to operate, interrupting service to customers on sections of the feeder not actually experiencing the short circuit. To remedy this potential problem, the TDU should add more advanced protection schemes to the system to detect the actual location of short circuit currents.

2. Do technical complications arise if DG exported to a feeder exceeds total feeder load? If so, please describe the nature of these complications, with detail on whether the relevant measure of feeder load is minimum, average, or maximum load, and identify possible solutions.

AEP responded that technical complications do arise if DG exported onto a feeder exceeds feeder load. Reverse power flow onto the substation bus would require modification of the protective scheme and metering in most situations because distribution systems have generally been planned, designed, and built for radial configurations. Also, the voltage regulation scheme may need modification for reverse flow. Flow will need to be within equipment and conductor ratings, which would not normally be a problem. In rare situations, DG injected harmonics could create problems with capacitor banks, static VAR compensation, and other similar station equipment. Meters on distribution feeders are used to determine present and future load requirements. The apparent load will be the load on the feeder net of any DG. The metering is intended to monitor this net of load and generation on the feeder may not register if net load is negative. To rectify this problem, meters that measure load flowing in either direction and the direction of flow may be needed.

EGSI commented that technical complications have the potential to be much more severe when DG levels approach or exceed the load served by common facilities. Because the DG would be expected to be a large contributor to or the controlling factor for the severity of the complications, the majority of any mitigation measures should be the responsibility of the DG. The primary solution to most scenarios would be to curtail or significantly reduce DG operations as often and whenever it is necessary to correct or alleviate the problems.

Reliant commented that the same problems as addressed in its response to question 1 would arise if DG on a feeder exceeds feeder load. Reliant also commented that DG may cause abnormal voltage levels outside of limits set in the commission's rules on feeders served by the same substation bus.

TXU commented that the same problems as addressed in its response to question 1 would arise if DG on a feeder exceeds feeder load. The cost of solutions escalates as the amount of exported DG increases. At some point, the only solution is to redesign, reconfigure, and significantly upgrade the interconnected feeder and possibly adjacent feeders at substantial cost. Also, since utility upgrades do not necessarily eliminate potential damage to customer equipment from excessive fault current, every customer on the feeder is potentially subject to upgrade costs on the customer's side of the meter. The factors that determine the upgrades on the distribution system needed to support DG are not solely related to feeder load. Technical complications can exist at all load levels on the feeder; however, the complexity and cost of solutions generally increases as the total amount of DG on a feeder approaches the ten MW design limit.

In its reply comments, TXU indicated that comments of others support its view that provisions of the current rule limiting the capacity of DG facilities to ten MW or less and allowing utilities to charge the DG customer for substantial upgrades avoid most of the technical and operational obstacles that might otherwise arise from DG.

3. Do technical complications arise if DG exported to all feeders served by a common substation exceeds substation load? If so, please describe the nature of these complications and possible solutions.

AEP commented that many of the complications addressed in its response to question 2 would also occur for a substation with more DG connected than load. When more DG is operating on a substation than load, an outage of the substation transformer is an additional occurrence that would result in a loss of generation to the system. This would usually not create system deficiencies since transformer and substation bus failures would be random as opposed to being associated with system disturbances. It could, however, create a need to adjust system generation schedules.

AEP also commented that transmission and generation system coordination would be affected since to the transmission and generation system, the substation bus would be a generator. Generator buses are used to meet system requirements under normal and adverse operating circumstances. These buses have unique relaying systems and system load is not connected to a common bus with a generator due to the operational requirements of a generator bus.

AEP commented that the most suitable resolution of this problem is to design systems for interconnecting the generation in a way other than with the distribution load. This would make the operation of the system feasible by making the generation a viable source to the generation and transmission system. It would not detract from the mission and ideals of DG since such an amount of generation will have exceeded the load in an area anyway.

EGSI commented that technical complications would arise if DG exported to all feeders served by a common substation exceeds substation load, as more fully discussed in its responses to questions 1 and 2.

Reliant commented that the same complications stated in its response to questions 1 and 2 may arise if DG exported to all feeders served by a common substation exceeds substation load. In addition, Reliant commented that for substations that have DG levels that exceed the substation load, the DG units may continue to maintain transmission voltage during a short circuit on the transmission line even after the transmission breakers have tripped. This would prevent the transmission breakers from reclosing and would result in a transmission line lockout instead of a momentary interruption. This situation would result in a loss of service to several substations and their associated customers. Reliant suggested that to solve this problem, the TDU should install additional potential and relaying devices on the transmission side of each substation transformer to trip the appropriate feeder breakers and disconnect the DG.

TXU commented that the scenario posed in this question creates the most difficult situation to handle and potentially the most significant and costly problems for the utility distribution system. First, fault current interrupting ratings of utility system equipment could be exceeded as could interrupting ratings for some customer-owned equipment for customers located close to the substation. Second, phasing problems could occur if DG were to remain on line during a disturbance and the feeder breaker were to cycle open and reclose back in with the DG out of phase, likely causing damage to DG equipment.

TXU also commented that safety problems could arise from delays in breaker and recloser operations due to the DG backfeeding various devices. Coordination of the feeder protection system can become very difficult, if not impossible, in some cases. And, the presence of exporting DG on a feeder has the potential to adversely interact with substation load tap changers which function as automatic voltage regulators to maintain acceptable feeder voltage under varying system operating conditions. Under the condition posed in question 3, it is possible that automatic voltage control would have to be forgone because of the need to lock down the load tap changers to prevent such interactions. This could result in a loss of automatic voltage control and adversely affect the system voltage and connected equipment.

TXU further commented that DG export feeding back into the transmission system poses problems due to the loss of ground reference through the substation transformer. This loss of ground reference results in a failure of communications between the transmission breakers and the DG that could result in the DG energizing the transmission system in a fault situation. In this condition, public safety could be severely compromised. Also, this loss of ground reference could destroy lightning arresters on the transmission system and voltage instability problems may exist with multiple DGs in operation.

TXU commented that to solve the potential problems associated with the condition posed in question 3, a number of steps would be necessary: replace the substation transformer; replace the substation bus with a higher rated bus; replace the substation breakers with higher rated breakers; replace the protective equipment on the feeders with higher rated equipment; provide transfer trip capabilities for all DG; make major modifications to the substation load tap changers to operate them in the proper manual mode; advise other customers that their circuit breaker ratings may have been exceeded; and make operational changes within the utility system to guard against possible phasing problems by insuring that the DG is taken off-line when necessary. TXU noted that these steps would be extremely costly.

4. Is there a market-related need to limit the amount of energy that a particular customer can export to the distribution system as a percentage of total feeder load?

AEP commented that to the extent DG can operate and satisfy the technical requirements of the utility, the DG should be free to operate within its specific market obligations and opportunities.

EGSI commented that it would be most economic to limit energy exported to the distribution system so that it did not exceed the total substation load at any point in time.

Reliant commented that, assuming there is not a feeder constraint, there is no market-related need to limit the amount of energy exported to the distribution system.

TXU commented that if there are competing DG facilities on the same feeder and concurrent generation could exceed the safe and prudent capabilities of the feeder and/or substation, the amount of energy that a particular customer can export to the distribution system as a percentage of total feeder load should be limited. The distribution utility should not be required to subsidize an exporting DG facility by upgrading an overloaded feeder that is otherwise adequately sized to meet the needs of existing distribution customers.

From the comments submitted, it appears that problems with significant amounts of DG on a feeder are not likely to arise in the near future due to the limited market penetration of DG. Substantive Rule

§25.212(c) of this title, Technical Requirements for Interconnection and Parallel Operation of On-site Distributed Generation, lists operational criteria in the areas of voltage, flicker, frequency, harmonics, and fault and line clearing and requires that the customer's generator meet these operational criteria to eliminate undesirable interference caused by operation of the customer's generating equipment. In addition, the rule establishes a process for identifying safety and reliability issues associated with DG projects and addressing these issues. Interconnection studies that are currently required under Substantive Rule §25.212(g) should identify any system upgrades that are needed to facilitate interconnection of a DG facility. Where interconnection of a particular DG facility would involve significant system upgrades, §25.211(m)(3) ensures that the DG facility owner, not the ratepayers, will be responsible for paying for those upgrades. Further, the provisions of §25.211(o) concerning interconnection disputes ensure that disputes concerning the level of system upgrades required by a utility for interconnection can be expeditiously addressed. No change was made in response to these comments.

The commission does not foresee that DG on a feeder in excess of feeder load, as set forth in question 2, is likely to become a problem in the near future due to the current low market penetration of DG. As DG becomes more prevalent, technical solutions to the problems identified by the utilities are likely to become more available at lower cost. For now, the interconnection requirements of commission rules address the issue of interconnection costs. No change was made in response to these comments.

The commission does not anticipate that the problems addressed in the responses to question 3 will become a significant issue until market penetration of DG substantially increases. No change was made in response to these comments.

Because of the limited market penetration of DG at this time, the commission does not see that there is a present need to address the potential circumstance raised by TXU in its response to question 4. As DG penetration increases along with the level of experience of the commission, the utilities, and DG customers, an appropriate solution to the potential problem outlined by TXU can be crafted when needed. No change was made in response to these comments.

5. Is there a need to address allocation of transmission charges among customers when the total DG exported to a feeder exceeds feeder load? If so, what is the best allocation method?

AEP commented that DG facilities that export generation that exceeds the native load on the feeder are by definition using the transmission system. Current transmission pricing does not properly take into account the existence of DG. In order for this issue to be addressed, ERCOT will need to develop policies related to DG export. AEP believes this is an issue for future workshops and development.

EGSI commented that there is no need to address allocation of transmission charges. The DG should be treated the same as a qualifying facility or independent power producer, with those rules used to determine charges.

Reliant and TXU commented that there is no need to address the allocation of transmission charges due to the current statute and current rules which recover transmission costs from all customers in ERCOT as determined on a statewide postage-stamp basis.

The commission agrees with TXU and Reliant that commission rules currently address allocation of transmission charges. The commission's policy regarding transmission charges is that the load pays. Entities receiving generation from a DG facility are responsible for any transmission charges associated with receipt of that generation. No change was made in response to these comments.

6. Is there a need to limit the amount of insurance that can be required of an exporting customer? Please explain why or why not. If there is a need to limit the amount of insurance that can be required of an exporting customer, please explain what the appropriate insurance requirements should be. Should insurance requirements vary with the size of the installation?

AEP commented that there is no need for the commission to limit the amount of insurance that can be required of an exporting customer. AEP noted that the commission previously considered a similar issue in Project Number 13868, *Consideration of Liability Insurance for Small Wind Generators*, concerning liability insurance for wind generators. In that project, the commission did not take action to amend existing rules by restricting the amount of the insurance requirements. AEP urged the commission to recognize that the liability and potential hazardous conditions are the same regardless of the size of the generator and it would be inappropriate to establish limits for insurance requirements for exporting customers.

EGSI commented that there should be a requirement for insurance at a level that will insure indemnification of the utility for the potential harm that a DG could cause. Allowing insurance to vary directly with the size of the DG will only encourage disregard for potential consequences of negligence and culpable behavior. The DG would typically have little investment and little to lose by simply walking away from reasonable claims that exceed the limits of its insurance and the value of the DG investment.

Reliant commented that there is no need to address the amount of insurance required of an exporting customer. Currently, issues relating to the limitation of liability and indemnification are addressed in Section 4 of the Agreement for Parallel Operation of Distributed Generation approved by the commission on November 18, 1999. Because the agreement contains the necessary provisions concerning the issue of liability and indemnification, any changes to the current rule would not be necessary. The utility and customer are bound by the agreement to indemnify against losses to the extent that they result from an act of negligence in the design, construction, or operation of the facilities. The level of insurance that the utility and customer choose to carry is a business decision that each must make independently. Whether or not the utility and customer have chosen to adequately insure themselves should not be of concern to the commission. Reliant further commented that it is unaware of any requirements that utilities can impose upon an exporting customer as to the levels of insurance.

TXU commented that the commission should not adopt limits on the amount of insurance that can be required of an exporting customer. The liabilities and potential hazards are the same regardless of the size of the generator. As the density of installed DG increases, the public exposure to the potential hazards of electrical generation will increase. Utilities must be able to ensure that exporting customers have either adequate assets or sufficient insurance to support their contractual indemnification obligations. TXU expressed its belief that it should be permitted to examine each proposed interconnection on a case-by-case basis to determine appropriate insurance requirements.

The commission appreciates the concerns expressed by utilities that they have a mechanism to ensure that the DG facility owner is financially able to indemnify the utility against loss due to the fault of the DG facility or its owner. However, allowing a utility to require proof of insurance at levels set on a case-by-case basis creates the potential for abuse by the utility. The commission is amenable to allowing case-by-case review of liability insurance requirements for the time being and until such time as it appears that one or more utilities are abusing their ability to impose insurance requirements on a case-by-case basis. The commission encourages DG customers who have concerns about the level of liability insurance required by a utility to interconnect to avail themselves of the dispute resolution provisions of §25.211(o).

7. Should the ten MW limit on interconnected capacity in the definition of "facility" be raised or eliminated altogether?

AEP responded that the ten MW limit in the definition of DG was intended to clearly identify DG for all stakeholders in Texas and is appropriate for 15 kV class distribution systems. To apply the requirements of the DG rule to larger units will very likely create complications that will require changes to the rules, further complicating and increasing the cost for DG applicants and utilities. Smaller units would be thrown into a process designed to accommodate larger units with requirements that might have been avoided had the ten MW limit remained in place. This is currently the dilemma faced by DG today when having to deal with ERCOT for transmission service. The ERCOT rules were designed for projects by large independent power producers, and not the needs of small-scale DG. AEP does not consider the ten MW limit in the rule as excluding DG with a capacity higher than ten MW. Nothing in the commission's rules prevents a party that wishes to interconnect a unit larger than ten MW from working with the distribution utility on a case-by-case basis.

AEP further commented that the commission can increase the size of DG for feeders of higher nominal operating voltage and still be consistent with the original intent. AEP recommended that the limit for 25 kV class distribution be set at 20 MW and the limit for 35 kV class distribution be set at 25 MW.

In its reply comments, TXU disagreed with AEP's recommendation that the limit for 25 kV class distribution be set at 20 MW and the limit for 35 kV class distribution be set at 25 MW. TXU claimed that the technical and operational problems discussed in its response to preamble questions 1-3 militate in favor of retaining the existing ten MW cap.

EGSI commented that the ten MW limit is reasonable and should be maintained. Only after the industry has more experience solving the problems of potentially significant penetration of the delivery system by

DG should the ten MW limit be reviewed. EGSI further commented that the ten MW limit should be applied to distribution system facilities served from a common substation source.

Reliant commented that due to the inherent physical limitations of a distribution feeder, the ten MW upper limit on DG should remain. The focus of the DG rules is distributed generation and ten MW is often the threshold for that designation.

SPS commented that the MW limit should remain in the definition of a facility. The distribution system is generally configured to carry small loads. Most locations on the distribution system would require significant upgrades to the system to accommodate large scale DG operations. The original purpose of encouraging DG was to allow an alternative for self-production of a customer's energy needs. The only purpose for increasing or eliminating the ten MW threshold would be to facilitate large-scale wholesale sales from distribution sources. The ten MW limit allows the utility to tailor specific charges for the studies required for siting and placement of DG. Larger scale operations would require much more flexibility as the costs associated with these operations vary a great deal more.

TXU also commented that, due to the inherent physical limitations of a distribution feeder, the ten MW upper limit on DG should remain. The rule as currently written is consistent with ERCOT Protocols which use ten MW as the limit for increased metering and telemetering requirements. The rule is also consistent with the statutory ten MW exemption for on-site generation regarding payment of transition charges.

The commission believes that it is appropriate at this point in time to retain the limit on DG to facilities generating ten MW or less of energy. As DG becomes more prevalent in the market and solutions to the problems identified by the utilities in questions 1-3 become more available and less costly, the commission may revisit the upper limit on DG. No change was made in response to this comment.

General Comments

In general comments concerning the proposed rule, Reliant commented that the commission has underestimated the administrative costs associated with setting up and operating a banking service. AEP recommended that the banking provisions be modified as suggested by TXU in its comments.

As discussed more fully in the response to comments concerning subsection (c)(2), the commission has modified the definition of banking to allow parties to a banking arrangement to develop a plan for disbursing banked energy in a manner that is reasonably anticipated to be revenue neutral.

EGSI commented that the proposed rule appeared to be written only with Texas ERCOT utilities in mind and does not contemplate issues, requirements, and regulatory oversight for non-ERCOT utilities. The proposed rule contains provisions that directly conflict with Federal Energy Regulatory Commission (FERC) tariffs and regulatory oversight. They also conflict with the Public Utility Regulatory Act (PURA) and the commission's own prior rulings.

The commission recognizes that a DG customer selling energy on a wholesale basis may be subject to FERC-approved open access tariffs that address energy imbalances and do not require banking services. When ERCOT switches to a single control area, the banking services required under this rule will also be replaced by an energy imbalance system managed by the ISO. DG customers will be able to negotiate an agreement with their retail electric provider (REP) for handling any imbalance fees associated with the DG customer's operations. The rule has been modified to address exporting DG customers interconnected to a distribution system operated by a non-ERCOT utility.

EGSI commented that the proposed rules provide subsidies to DG which will be assessed to other parties. EGSI indicated that the subsidies are in various forms: no ability to assess charges for additional facilities required by DGs to attach to and operate on the utility system; DGs will not pay the costs others pay for the same standby and ancillary services associated with transmission facilities and generation capacity; DGs will not pay the costs to acquire and maintain the new power accounting and transaction systems that will be required to bank energy; and DGs will not be required to pay the potentially significant cost differential between the value of banked energy and the returned energy.

The commission disagrees with EGSI's comments. Current commission rules provide a mechanism for a utility to assess significant interconnection costs to the DG facility owner. Routine interconnection costs are borne by ratepayers generally in recognition of the fact that in many instances DG benefits the distribution system and lowers distribution system operating costs. The proposed rule amendments do not preclude assessment of charges to a DG facility for standby and ancillary services, as contended by EGSI. Further, the commission anticipates that reasonable expenses associated with establishing systems for providing banking services will be captured in the banking fee tariff. Finally, as noted above, the commission has determined that modifications to the proposed definition of banking are needed to ensure that they are fair for both the utility and DG facility owners. No change was made in response to these comments.

EGSI commented that the proposed amendments are unnecessary, costly, and burdensome for the short duration they will be in effect. DGs can be reasonably and equitably accommodated today by rules and regulations that are in place today for qualifying facilities (QFs) and independent power producers (IPPs). Non-ERCOT utilities should not be subject to the amendments to these rules.

The commission has found that there is a need for the proposed amendments and disagrees with EGSI's comments that they are unnecessary, costly and burdensome. The commission has found that the rules in place for IPPs are designed for large projects and create barriers to DGs that are ten MW or smaller.

EGSI commented that under the Public Utility Regulatory Policy Act (PURPA), a non-ERCOT utility is obligated to take power when and if it is available from a QF. The QF is paid the utility's avoided cost and banking is not allowed. Therefore, these proposed rules appear to provide customers with more flexibility and rights than intended by PURPA and is a violation of PURPA. While a utility is required to purchase the energy as available under PURPA the intent was to keep other customers neutral as to whether the utility generated or purchased this energy from the QF. If the banking portion of the proposed amendment is approved, other customers will subsidize the DG customers. These subsidies are contradictory to the intent of Senate Bill 7, 76th Legislative Session, which was to create a competitive market for the sale of electricity.

As discussed generally above, the commission disagrees that the rule would provide illegal subsidies to DG customers. The only provision of the rule for cost sharing relates to standard interconnection costs for DG customers. However, as DG generally provides a benefit to the distribution system, other customers will realize benefits from DG interconnection that will ultimately more than offset the cost of interconnection. The commission concludes that these rules are not contrary to PURPA. That law provides specific rights to qualifying facilities. The benefits in this rule would apply to generators of less than ten MW regardless of whether they are QFs. To the extent that specific conflicts with FERC tariffs are identified, the commission will relieve non-ERCOT utilities from the obligations of this rule.

EGSI expressed concern about the proposed banking requirements. EGSI claimed that the amendment was in direct conflict with FERC regulations. Connection of DGs to the EGSI distribution system has already been addressed in EGSI's FERC Generator Imbalance Tariff (GIT). The fact that a generator is interconnected at a distribution voltage does not obviate its reliance on the transmission system. As such, a DG is subject to the provisions of EGSI's Open Access Transmission Tariff (OATT) including the GIT. Pursuant to that tariff, if a generator is producing power, it must either be a network resource or have a point-to-point schedule from it to a load. If it is a network resource, then its actual output is credited to the network load and there is no imbalance. If it is a point-to-point supplier, then any discrepancy between the schedule and output is handled by the GIT and is either purchased by EGSI based upon its avoided cost or purchased by the supplier based on EGSI's incremental cost. There is no provision for banking.

The commission agrees that the proposed banking requirements should not be applied to an exporting DG customer interconnected to a distribution system operated by a non-ERCOT utility. The rule has been revised accordingly.

Further, EGSI claimed that the provision of banking service requires the bank to have capacity. If the customer of the banking service does not pay a capacity charge, it is being subsidized by those that pay for the capacity. The banking provision, as envisioned in the draft rules, cannot apply to FERC-regulated utilities and is plainly prohibited by PURA.

As previously discussed, the proposed banking provisions have been revised to provide that they do not apply to a distribution system operated by a non-ERCOT utility and to provide that the banking agreement between the DG customer and the utility should be structured in such a manner as to be revenue neutral. These changes address the concerns expressed by EGSI in this comment. No further changes were made in response to this comment.

EGSI further commented that the proposed rule is in conflict with §25.341 of this title, Definitions, in that banking is a form of hedging and risk management, a competitive energy service.

The commission disagrees that banking is a form of hedging and risk management. Banking is a mechanism that allows DG facilities generating at less than whole (integer) megawatt units to schedule their generation. No change was made in response to this comment.

EGSI also disputed the assertions in the preamble that the proposed changes will have minimal economic cost. The banking provisions will have potential for costs to be assessed to utilities or their customers. Every kilowatt-hour of energy banked by a DG has the potential to impose additional costs on the utility. Utilities should be able to recover these costs through fuel recovery mechanisms. EGSI expressed concern about the ability of a DG customer to bank energy during off peak hours and then order its delivery during on peak hours at substantial potential cost to the utility. Alternatively, DG could operate when the energy input into the system is economically costly to other customers such as when, during system minimum load conditions, the utility must incur costs to keep generation on-line and available for the next day's peak demand. If the DG places energy into the system during those low load periods and displaces energy that would otherwise be served by system generation, then all customers are subsidizing the DG through the additional fuel and operations and maintenance (O&M) costs incurred during those low load periods.

The commission foresees minimal economic impact resulting from the banking provisions due to the low penetration of DG.

EGSI further noted that the rules are silent on the handling of banked energy as of January 1, 2002. Would the utilities have to return it or would the DGs lose it?

The commission concludes that this issue can be resolved by agreement between a DG owner and a utility.

EGSI commented that the proposed amendments do not specify the circumstances under which a purchaser of energy from an exporting customer may be assessed distribution and transmission-related charges as is contemplated in the preamble. Because the rule is silent on this issue, it can be assumed that the standard and normal fees and charges appropriate for such services will be assessed to the customer receiving the energy. Further, the draft rules speak only to the prohibition of fees and charges applied to exported energy. A logical inference is that fees can be applied to the return of banked energy. If fees can be applied to exported energy then the draft rules do not speak to such issues as creditworthy arrangements for those that receive the exported power.

The proposed rule specifically provides that distribution and transmission charges cannot be assessed to the exporting DG customer. The rules generally do not prohibit assessments of transmission and distribution charges against the entity receiving exported energy from the DG customer, consistent with the commission's rules for ERCOT transmission service, which require load-serving utilities to pay for transmission service. In the case of charges associated with use of the distribution system to which the DG customer is interconnected, the commission would expect that no distribution charges would be assessed in accordance with each utility's tariff, which would typically require payment for power delivered to the customer or in connection with standby service. Creditworthiness for a DG would become an issue only if the DG owner needed to purchase transmission service or ancillary services. These issues can be addressed under the tariffs for such service.

SPS commented that energy that is exported from a DG facility should be classified as wholesale energy. Exported DG can be transported across state lines. The FERC asserts its jurisdiction over charges for transmission and distribution of sales of this nature. Also, PURA explicitly forbids the sale of electricity from a non-utility to retail customers prior to competition. Therefore, the exported energy from DG units must be sold to non-end-use customers as wholesale energy. After retail access, energy must be sold to end-use customers by a licensed retail electric provider (REP). Classifying exported DG as wholesale power will eliminate confusion when sorting out FERC charges to FERC customers.

The commission concludes that, while SPS is correct, the proposed change is unnecessary. No change was made in response to this comment.

SPS also commented that the rule provides no certainty that the energy would be exported to the utility system or in what volume; therefore, the energy has no capacity value. However, the rule allows the

DG customer to ask that energy be disbursed at its discretion. This has the effect of allowing the DG customer to resell the banked energy at a MW level much greater than was ever put into the system by the DG facility. The vagueness of the rule provision erodes the value of the benefits of the DG to the utility system. The banking requirement should be revised so that the banked energy cannot be assigned any capacity value. This could be accomplished by requiring that all banked energy be released the following months across all hours of the month in the form of a credit to the customer's bill rather than to be dispatched at the DG customer's discretion.

In reply comments, EDI indicated that it does not agree with SPS' assertion that banked energy would create too much value to exporting generators nor that DG has no capacity value. Banking addresses two issues associated with DG. First, scheduling in less than one MW increments is prohibited under ERCOT rules. EDI generates in 1.3 MW increments. EDI would lose that 0.3 MW each hour. Banking allows EDI to schedule in whole MW increments. Second, daily scheduling charges are cost prohibitive for small DG. The purpose of banking is not to store off-peak energy and then sell or deliver it as on-peak energy, nor is the purpose of banking to hold on to energy in a rising market and sell that energy at a premium. Rather, it is to facilitate the delivery of electricity. DG can meter both on-peak and off-peak power separately, allowing for scheduling and delivery separately. Landfill gas generated power does have capacity value and sells at a premium because of that value. EDI does not agree that DG energy should be classified as wholesale energy. If PURA rules prevent DG energy from being sold at retail by a non-utility, then it will not happen.

In reply comments, TXU disagreed with SPS's suggestion that the banking requirement be revised to require banked energy to be released the following month in the form of a credit to the customer's bill. SPS's proposal does not mitigate the potential risk of banking to the utility and creates administrative problems and costs that should be avoided.

As previously discussed, the commission has revised the banking requirements to allow negotiation of banking agreements that are revenue neutral. The commission believes the revised banking requirements provide a superior approach to that suggested by SPS for handling the needs of DG customers. As discussed by EDI, scheduling charges are in part driving the need for utilities to provide banking services. No change was provided in response to SPS' comment.

Subsection (c)(2)

TXU commented that banking is a new concept not part of the current rule. As proposed, it gives the DG customer unilateral control over when energy is produced and when energy is delivered. This would permit the DG customer to bank low-cost energy and to direct the utility to disburse high-cost energy. This potential for gaming by DG customers could cause the utility to incur unmanageable risks of substantial financial loss. If banking is required, it should be equitable. The rules of operation of the bank should ensure that the electric utility is not put at financial or operational (*i.e.*, capacity) risk through providing this service. The electric utility should be allowed to negotiate with the DG owner to reach agreement on an equitable schedule for delivery and disbursement of energy. To address these issues, TXU recommended specific revisions to the proposed definition of banking.

The commission agrees that banking services should be provided in a manner that is revenue-neutral for both host control area, the receiving control area, and the DG customer. The commission has therefore revised the definition of banking as recommended by TXU with the exception that the commission has also required that the agreement be acceptable to the DG customer. The commission urges utilities to negotiate cooperatively to avoid agreements that frustrate the DG customer's business purpose. The commission will expeditiously consider and rule on any complaint received from a DG customer concerning allegations of an unfair banking agreement.

Subsection (c)(10)

Small Hydro of Texas, Inc. (SHOT) recommended that the definition of "on-site distributed generation" in subsection (c)(10) be revised to delete any requirement that DG be interconnected at 60 kV or lower. A generating facility that otherwise meets the requirements for on-site DG should not be disqualified under the rule simply because it is interconnected at 60 kV or greater. A small DG facility should not be barred from the protections afforded DG just because it happens to be interconnected to a utility's transmission system rather than its distribution facilities. In many cases, this may be the only economic option available to the generator because of its location. The legislature gave no indication that units that otherwise met all of the requirements should not be treated as DG simply because they were interconnected at the transmission level.

AEP commented in opposition to the comments of SHOT. SHOT's request would actually deny to DG owners the benefits of streamlining and standardizing the interconnection process. The additional complexity of transmission level interconnections would thwart the original intent and purpose of §25.211 and §25.212. In addition, extending the DG rule to non-distribution voltages would put it in direct conflict with interconnection procedures and requirements that have been established for transmission voltage interconnections by the ERCOT ISO. The existing DG rules are strengthened by their focused application of the principles to small units when interconnected with distribution facilities. Removing this limit on the application of the rules dilutes their strength and undermines the commission's purpose in adopting the rules. Should the commission adopt SHOT's proposal and raise the ten MW limit, AEP questions how the commission would differentiate distributed generation from other generation in the future. The DG rules should not be amended to accommodate special wholesale market issues. Transmission policy in Texas has been formulated without DG in mind and current transmission pricing does not properly take into account the existence of DG. The proper course of action would be to rectify this situation and accommodate DG as well as small scale generation interconnected at transmission voltage as appropriate. Should the DG rule be expanded to encompass facilities that are connected at transmission voltage, AEP would have additional issues that would have to be covered that are clearly beyond the scope of this rulemaking.

In its reply comments, TXU recommended that the commission reject the proposal to allow transmission-level generation to be treated as DG, a proposal that is inconsistent with the original intention of both the legislature and the commission in promoting DG and raises other problems that have not been addressed or contemplated by these rule amendments. Adoption of SHOT's proposal would significantly change the risks and obligations previously contemplated by §25.211 and §25.212. It would entail both a modification to the rule and a revision to the commission-approved Agreement for Interconnection and Parallel Operation of Distributed Generation and an evaluation of whether other provisions contained in or assumptions underlying current rules would also have to be altered. Transmission-level generation invokes different technical interconnection issues and other questions related to capacity payments and sale to different markets that were not contemplated by this rulemaking.

The commission agrees with SHOT that a small DG facility should have access to the protections afforded DG customers under the DG rule. However, the commission is wary of extrapolating this rule to small generators which interconnect at transmission voltage rather than distribution voltage without further discussion and evaluation of the implications of such a change in the rule. The commission also notes that utilities have the flexibility to apply the concepts in this rule to small generators interconnected at transmission voltage. AEP has suggested that small generators interconnected at transmission voltage should be accommodated by utilities as appropriate on a case-by-case basis. The commission believes that this may be an appropriate solution to the problem identified by SHOT in the short term and until utility abuses are identified by the commission. Therefore, the commission declines to adopt SHOT's recommendation at this time. However, the commission expects as a matter of policy that the utilities will apply the same principles and practices to DG interconnecting at transmission as at distribution. The commission will monitor utility treatment of DG interconnection at transmission levels as well as at distribution and may address this issue in the future, if it identifies a need to specifically accord small generators interconnected at transmission voltage regulatory protections currently afforded to DG customers.

Subsection (d)(1)

TXU commented that there will be no need for banking service after June 1, 2001, when ERCOT will transition to a single control area. If banking service were to continue after ERCOT is operated as a single control area, it would cause uninstructed deviation in a qualified scheduling entity's (QSE's) schedule which may result in additional cost to the DG customer. TXU therefore recommended that subsection (d)(2) be revised to require banking service until only June 1, 2001.

TXU proposed a five to thirty day banking period, which would effectively reduce the banking period to five days. The rule anticipated a monthly banking period. Adding the words "at customer's direction" after the five to thirty-day language would be acceptable. Additionally, any prearranged schedule should attempt to keep the host utility, the delivering utility, and the customer neutral with respect to the market, not just the host utility. EDI responded that it would prefer to see the date in terms of service remain at December 31, 2001.

AEP and TXU suggested modifications to address the financial and operational risks associated with the commission's proposed amendments and to create a banking system that does not shift the financial and operational risks to the distribution utility.

The commission agrees that the rule should not require utilities to provide banking services after ERCOT begins to operate the transmission system as a single control area for the reasons raised by TXU. Therefore, the rule has been revised to require that banking service be provided only until the ERCOT ISO begins to operate ERCOT as a single control area. Thereafter, individual agreements negotiated between DG customers and QSEs should replace the need for banking services. As to EDI's comments regarding the definition of banking, the commission understands EDI's concerns about imposition of undue scheduling fees on the DG customer. One of the purposes of the required banking arrangement is to establish reasonable scheduling fees that can be imposed against a DG customer moving only a small amount of generation on the grid. Under the definition proposed by TXU and adopted by the commission, the utility and DG customer will be able to negotiate a banking agreement that serves their needs and imposes reasonable scheduling fees. The commission encourages DG customers which have difficulty negotiating appropriate banking arrangements with utilities to file complaints with the commission for rapid resolution.

Subsection (d)(2)

AEP commented that it believes that the commission intends subsection (d)(2) and (5) to further the commission's policy that load pays. AEP is concerned, however, that the utility itself will be considered the load and will be forced to pay or absorb the distribution line charges and transmission charges. AEP is not aware of any provision of PURA that requires the utility to purchase energy from exporting customers or any provision that requires the utility to absorb all distribution and transmission charges associated with the exporting customer's use of the distribution and transmission system.

EDI replied to AEP's comments indicating disagreement with AEP's suggestion that the exporting customer should pay distribution and transmission line charges. The physical power that a DG puts into the system stays at the distribution level. This results in a savings to the host utility that otherwise would have to deliver by transmission and distribution lines to supply the feeder that the DG is supplying.

The commission believes that AEP's concerns are misplaced. The commission anticipates that a DG customer will not move energy onto the grid unless it has a buyer for that energy. Without a designated buyer, the DG customer will not get paid for its energy. Nothing in commission rules suggests that the utility becomes the DG customer's designated buyer by default. In response to EDI's comments, the commission notes that the provisions of the rule concerning assessment of transmission and distribution charges are consistent with the commission's policy that load pays for delivery service.

Subsection (d)(3)

EGSI objected to the provisions of subsection (d)(3) prohibiting assessment of the costs of operating and maintaining the utility's interconnection equipment against the DG customer. O&M costs must be collected for facilities installed and used for the purpose of delivering, metering, and monitoring power from the DG to the system. Those facilities installed solely to accommodate the DG would not be already covered by tariffs for delivery of power to all customers. O&M costs should be born by either the exporting DG customer or the entity receiving the energy. Otherwise, the DG customer will enjoy a direct subsidization paid by other system users.

The commission disagrees with this comment. As discussed previously, DG provides a benefit to the entire system. Therefore, any additional costs of interconnecting DG will ultimately be more than offset by the system benefits associated with DG. No change was made in response to this comment.

Subsection (d)(4)

TXU commented that the proposed rule language is unclear. It should be modified to specify that scheduling fees apply to banked energy at the time the energy is scheduled to be delivered from the host control area to the receiving control area. With this change, the exporting DG would only pay scheduling fees when the banked energy is actually scheduled to be delivered to the receiving control area. TXU recommended specific modifying language.

EDI replied to TXU's proposed change. If the definition of banking includes a five-day period, then that is likely to be the banking period. This rule language is fine if the banking period can be up to 30 days.

AEP commented in support of TXU's proposed changes.

The commission generally agrees with TXU. The commission intended in the original rule to limit scheduling fees to a one-time charge for disbursement of energy. The commission has revised the rule accordingly.

Subsection (d)(5)

TXU commented that the proposed rule language should be changed to clarify the entity being referred to and the charges being discussed. Specifically, TXU suggested that the phrase "an exporting generator" be substituted for "a customer for exporting energy" and "access" be substituted for "line" in reference to transmission charges.

EDI commented that TXU's comments appear to be changing the transmission charges, not clarifying them. EDI preferred to leave the definition as transmission line charges, unless line and access mean the same thing in this context.

AEP commented in support of TXU's proposed changes as they create a banking system that does not shift the financial and operational risk to the distribution utility.

The commission agrees with TXU in part. The commission disagrees that the term "an exporting generator" should be substituted for "customer for exporting energy." Under the rule, interconnected DG operators are termed "customers." The provisions of the rule concerning assessment of charges to customers for exporting energy are intended to foster the commission's policy that load, not the exporting customer, pays for use of the transmission and distribution systems. The commission agrees that the rule should be clarified to prohibit assessment of either access or line charges against the exporting customer.

Subsection (d)(6)

AEP, EGSI, Reliant, and TXU commented that the contract reformation provisions of the proposed rule should be revised to apply only to those contracts executed after December 21, 1999, the original effective date of substantive rule §25.211 and §25.212. AEP further commented that no contract reformation should be required unless the DG customer agrees, while EGSI and Reliant commented that no contract should be reformed unless both parties agree. Reliant and TXU commented that the utility and DG customer should have the option to decide not to reform their contract. AEP further recommended that the contract reformation deadline be within 60 days of adoption of the rule amendment or within 60 days of the adoption of a commission-approved interconnection agreement form, whichever is later. In reply comments, AEP commented in favor of TXU's proposed revisions.

The commission generally disagrees. The commission believes that every DG customer, including a customer that signed a contract with a utility prior to the initial adoption of this rule, should have access to the mechanisms accorded under this rule, as amended. The commission agrees, however, that contract reformation should not be required where both the utility and the DG customer express a desire to retain their original contract. The rule has been revised accordingly.

Subsection (d)(7)

AEP sought clarification of the action required of utilities under this provision. AEP indicated that it assumed the commission intended that utilities would update their §25.211 compliance tariffs with banking and scheduling fee information. AEP reminded the commission that AEP wholesale transactions that include the banking and scheduling fees must also be filed at FERC.

AEP has properly interpreted this rule. The commission does not believe that further clarification is needed. No change was made in response to this comment.

EGSI commented that subsection (d)(7) should allow a 60-day period for amendment of applicable tariffs. In reply comments, TXU agreed that a 20-day period for amendment of applicable tariffs was too short and suggested that 30 days would be more reasonable.

The commission agrees that the 30-day period recommended by TXU is reasonable and has changed the rule accordingly.

All comments, including any not specifically referenced herein, were fully considered by the commission.

This amendment is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2000) (PURA), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; and specifically, PURA §39.101(b), which grant(s) the commission authority to ensure that electric customers have access to on-site distributed generation and to providers of energy generated by renewable energy resources.

Cross Reference to Statutes: Public Utility Regulatory Act §14.002 and §39.101(b).

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

(a) **Application.** Unless the context clearly indicates otherwise, in this section and §25.212 of this title (relating to Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation) the term "electric utility" applies to all electric utilities as defined in the Public Utility Regulatory Act (PURA) §31.002 that own and operate a distribution system in Texas. This section shall not apply to an electric utility subject to PURA §39.102(c) until the expiration of the utility's rate freeze period.

(b) **Purpose.** The purpose of this section is to clearly state the terms and conditions that govern the interconnection and parallel operation of on-site distributed generation in order to implement PURA §39.101(b)(3), which entitles all Texas electric customers to access to on-site distributed generation, to provide cost savings and reliability benefits to customers, to establish technical requirements that will promote the safe and reliable parallel operation of on-site distributed generation resources, to enhance both the reliability of electric service and economic efficiency in the production and consumption of electricity, and to promote the use of distributed resources in order to provide electric system benefits during periods of capacity constraints. Sales of power by a distributed generator in the wholesale market are subject to the provisions of this title relating to open-access comparable transmission service for electric utilities in the Electric Reliability Council of Texas (ERCOT).

(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 clearly indicates otherwise:

(1) **Application for interconnection and parallel operation with the utility system or application** — The standard form of application approved by the commission.

(2) **Banking** — A method of accounting for energy produced by a customer for export into the distribution system. The host control area accepts energy from the customer to meet its own energy needs during a five- to 30-day period, credits this energy to the customer's account, and subsequently produces and, in the five- to 30-day period immediately following acceptance of the energy, disburses the energy accrued under the customer's account to the receiving control area specified by the customer. Disbursement of the accrued energy shall follow a pre-arranged schedule mutually acceptable to the host control area, the receiving control area, and the DG customer. Such schedule shall attempt to keep the host control area neutral with respect to the market value of the energy transferred on behalf of the exporting customer.

(3) **Company —** An electric utility operating a distribution system.

(4) **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.

(5) **Facility** — An electrical generating installation consisting of one or more on-site distributed generation units. The total capacity of a facility's individual on-site distributed generation 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.

(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 by a customer 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 —** A 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 —** A company utility system is considered stabilized when, following a disturbance, the system returns to the normal range of voltage and frequency for a

duration of 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 DG 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) **Banking.** A company operating in ERCOT shall make banking services available to any customer upon the customer's request. This obligation continues until the ERCOT Independent System Operator begins operating ERCOT as a single control area.

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

(3) **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.

(4) **Scheduling fees.** A one-time scheduling fee for each banking period may be assessed for the disbursement of banked energy. No other scheduling fees may be assessed against an exporting DG customer.

(5) **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.

(6) **Contract reformation.** All interconnection contracts shall be conformed to meet the requirements of this section within 60 days of adoption.

(7) **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, including tariffs for banking and scheduling fees, 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 until January 1, 2002. 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. After January 1, 2002, the distribution utility shall not be responsible for the provision of generation services or their related charges.

(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 DG on the customer's premise 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 (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 can not 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 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. 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 distributed generation facilities no longer interconnected with the utility's system since the previous report, the capacity of each facility, 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) **Interconnection disputes.** Complaints relating to interconnection disputes under this section shall be handled in an expeditious manner pursuant to §22.242 (relating to Complaints). In instances where informal dispute resolution is sought, complaints shall be presented to the Electric Division. The Electric Division shall attempt to informally resolve complaints within 20 business days of the date of receipt of the complaint. Unresolved complaints shall be presented to the commission at the next available open meeting.

This agency hereby certifies that the rule, as adopted, 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.

ISSUED IN AUSTIN, TEXAS ON THE 18th DAY OF DECEMBER 2000.

PUBLIC UTILITY COMMISSION OF TEXAS

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Chairman Pat Wood, III

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Commissioner Judy Walsh

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Commissioner Brett A. Perlman