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§25.1. Purpose and Scope of Rules.

(a) **Mission of the Public Utility Commission of Texas (commission)**. The mission of the commission is to assure the availability of safe, reliable, high quality services that meet the needs of all Texans at just and reasonable rates. To accomplish this mission, the commission shall regulate electric and telecommunications utilities as required while facilitating competition, operation of the free market, and customer choice.

(b) This chapter is intended to establish a comprehensive system to accomplish the mission of the commission with respect to electric service and to establish the rights and responsibilities of the electric utilities, including transmission and distribution utilities, non-utility wholesale and retail market participants, and electric customers. This chapter shall be given a fair and impartial construction to obtain these objectives and shall be applied uniformly regardless of race, creed, color, national origin, ancestry, sex, marital status, lawful source of income, level of income, disability, or familial status.

§25.2. Cross-Reference Transition Provision.

A reference in a rule section or part of a section of Chapter 22 of this title (relating to Procedural Rules); Chapter 23 of this title (relating to Substantive Rules); Chapter 24 of this title (relating to Policy Statements); Chapter 25 of this title (relating to Substantive Rules Applicable to Electric Service Providers); or Chapter 26 of this title (relating to Substantive Rules Applicable to Telecommunications Service Providers) to another section or part of a section of Chapter 23 that was repealed after January 1, 1998, refers to the corresponding section in Chapter 25 or Chapter 26 that replaced the Chapter 23 section.

§25.3. Severability Clause.

(a) The adoption of this chapter does not preclude the Public Utility Commission of Texas (commission) from altering or amending any sections of this chapter in whole or in part, or from requiring any other or additional services, equipment, facilities, or standards, either upon complaint or upon its own motion or upon application of any person. Furthermore, this chapter will not relieve electric utilities, including transmission and distribution utilities, non-utility wholesale and retail market participants, or electric customers from any duties under the laws of this state or the United States. If any provision of this chapter is held invalid, such invalidity shall not affect other provisions or applications of this chapter which can be given effect without the invalid provision or application, and to this end, the provisions of this chapter are declared to be severable. This chapter shall not be construed so as to enlarge, diminish, modify, or alter the jurisdiction, powers, or authority of the commission.

(b) The commission may make exceptions to this chapter for good cause.

§25.4. Statement of Nondiscrimination.

(a) No electric utility or retail electric provider shall discriminate on the basis of race, creed, color, national origin, ancestry, sex, marital status, lawful source of income, level of income, disability, or familial status.

(b) No electric utility or retail electric provider shall unreasonably discriminate on the basis of geographic location.

§25.5. Definitions.

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise:

(1) **Above-market purchased power costs** -- Wholesale demand and energy costs that a utility is obligated to pay under an existing purchased power contract to the extent the costs are greater than the purchased power market value.

(2) **Affected person** -- means:
  - (A) a public utility or electric cooperative affected by an action of a regulatory authority;
  - (B) a person whose utility service or rates are affected by a proceeding before a regulatory authority; or
  - (C) a person who:
    - (i) is a competitor of a public utility with respect to a service performed by the utility; or
    - (ii) wants to enter into competition with a public utility.

(3) **Affiliate** -- means:
  - (A) a person who directly or indirectly owns or holds at least 5.0% of the voting securities of a public utility;
  - (B) a person in a chain of successive ownership of at least 5.0% of the voting securities of a public utility;
  - (C) a corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by a public utility;
  - (D) a corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by:
    - (i) a person who directly or indirectly owns or controls at least 5.0% of the voting securities of a public utility; or
    - (ii) a person in a chain of successive ownership of at least 5.0% of the voting securities of a public utility;
  - (E) a person who is an officer or director of a public utility or of a corporation in a chain of successive ownership of at least 5.0% of the voting securities of a public utility; or
  - (F) a person determined to be an affiliate under Public Utility Regulatory Act §11.006.

(4) **Affiliated electric utility --** The electric utility from which an affiliated retail electric provider was unbundled in accordance with Public Utility Regulatory Act §39.051.

(5) **Affiliated power generation company (APGC) --** A power generation company that is affiliated with or the successor in interest of an electric utility certificated to serve an area.

(6) **Affiliated retail electric provider (AREP) --** A retail electric provider that is affiliated with or the successor in interest of an electric utility certificated to serve an area.

(7) **Aggregation --** Includes the following:
  - (A) the purchase of electricity from a retail electric provider, a municipally owned utility, or an electric cooperative by an electricity customer for its own use in multiple locations, provided that an electricity customer may not avoid any non-bypassable charges or fees as a result of aggregating its load; or

(B) the purchase of electricity by an electricity customer as part of a voluntary association of electricity customers, provided that an electricity customer may not avoid any non-bypassable charges or fees as a result of aggregating its load.

(8) **Aggregator** -- A person joining two or more customers, other than municipalities and political subdivision corporations, into a single purchasing unit to negotiate the purchase of electricity from retail electric providers. Aggregators may not sell or take title to electricity. Retail electric providers are not aggregators.

(9) **Ancillary service --** A service necessary to facilitate the transmission of electric energy including load following, standby power, backup power, reactive power, and any other services the commission may determine by rule.

(10) **Base rate** -- Generally, a rate designed to recover the cost of service other than certain costs separately identified and recovered through a rider, rate schedule, or other schedule. For bundled utilities, these separately identified costs may include items such as a fuel factor, power cost recovery factor, and surcharge. Distribution service providers may have separately identified costs such as transition costs, the excess mitigation charge, transmission cost recovery factors, and the competition transition charge.

(11) **Bundled Municipally Owned Utilities/Electric Cooperatives (MOU/COOP)** -- A municipally owned utility/electric cooperative that is conducting both transmission and distribution activities and competitive energy-related activities on a bundled basis without structural or functional separation of transmission and distribution functions from competitive energy-related activities and that makes a written declaration of its status as a bundled municipally owned utility/electric cooperative pursuant to §25.275(o)(3)(A) of this title (relating to Code of Conduct for Municipally Owned Utilities and Electric Cooperatives Engaged in Competitive Activities).

(12) **Calendar year** -- January 1 through December 31.

(13) **Commission** -- The Public Utility Commission of Texas.

(14) **Competition transition charge (CTC) --** Any non-bypassable charge that recovers the positive excess of the net book value of generation assets over the market value of the assets, taking into account all of the electric utility's generation assets, any above market purchased power costs, and any deferred debit related to a utility's discontinuance of the application of Statement of Financial Accounting Standards Number 71 ("Accounting for the Effects of Certain Types of Regulation") for generation-related assets if required by the provisions of the Public Utility Regulatory Act (PURA), Chapter 39. For purposes of PURA §39.262, book value shall be established as of December 31, 2001, or the date a market value is established through a market valuation method under PURA §39.262(h), whichever is earlier, and shall include stranded costs incurred under PURA §39.263. Competition transition charges also include the transition charges established pursuant to PURA §39.302(7) unless the context indicates otherwise.

(15) **Competitive affiliate** -- An affiliate of a utility that provides services or sells products in a competitive energy-related market in this state, including telecommunications services, to the extent those services are energy-related.

(16) **Competitive energy efficiency services** -- Energy efficiency services that are defined as competitive energy services pursuant to §25.341 of this title (relating to Definitions).

(17) **Competitive retailer --** A retail electric provider; or a municipally owned utility or electric cooperative, that has the right to offer electric energy and related

services at unregulated prices directly to retail customers who have customer choice, without regard to geographic location.

(18) **Congestion zone** -- An area of the transmission network that is bounded by commercially significant transmission constraints or otherwise identified as a zone that is subject to transmission constraints, as defined by an independent organization.

(19) **Control area** -- An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(A) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(B) maintain, within the limits of good utility practice, scheduled interchange with other control areas;

(C) maintain the frequency of the electric power system(s) within reasonable limits in accordance with good utility practice; and

(D) obtain sufficient generating capacity to maintain operating reserves in accordance with good utility practice.

(20) **Corporation** -- A domestic or foreign corporation, joint-stock company, or association, and each lessee, assignee, trustee, receiver, or other successor in interest of the corporation, company, or association, that has any of the powers or privileges of a corporation not possessed by an individual or partnership. The term does not include a municipal corporation or electric cooperative, except as expressly provided by the Public Utility Regulatory Act.

(21) **Critical loads** -- Loads for which electric service is considered crucial for the protection or maintenance of public health and safety; including but not limited to hospitals, police stations, fire stations, critical water and wastewater facilities, and customers with special in-house life-sustaining equipment.

(22) **Customer choice** -- The freedom of a retail customer to purchase electric services, either individually or through voluntary aggregation with other retail customers, from the provider or providers of the customer's choice and to choose among various fuel types, energy efficiency programs, and renewable power suppliers.

(23) **Customer class** -- A group of customers with similar electric service characteristics (e.g., residential, commercial, industrial, sales for resale) taking service under one or more rate schedules. Qualified businesses as defined by the Texas Enterprise Zone Act, Texas Government Code, Title 10, Chapter 2303 may be considered to be a separate customer class of electric utilities.

(24) **Day-ahead** -- The day preceding the operating day.

(25) **Deemed savings** -- A pre-determined, validated estimate of energy and peak demand savings attributable to an energy efficiency measure in a particular type of application that a utility may use instead of energy and peak demand savings determined through measurement and verification activities.

(26) **Demand** -- The rate at which electric energy is delivered to or by a system at a given instant, or averaged over a designated period, usually expressed in kilowatts (kW) or megawatts (MW).

(27) **Demand savings** -- A quantifiable reduction in the rate at which energy is delivered to or by a system at a given instance, or averaged over a designated period, usually expressed in kilowatts (kW) or megawatts (MW).

(28) **Demand-side management (DSM)** -- Activities that affect the magnitude or timing of customer electrical usage, or both.

(29) **Demand-side resource or demand-side management** -- Equipment, materials, and activities that result in reductions in electric generation, transmission, or distribution capacity needs or reductions in energy usage or both.

(30) **Disconnection of service** -- Interruption of a customer's supply of electric service at the customer's point of delivery by an electric utility, a transmission and distribution utility, a municipally owned utility or an electric cooperative.

(31) **Distribution line --** A power line operated below 60,000 volts, when measured phase-to-phase, that is owned by an electric utility, transmission and distribution utility, municipally owned utility, or electric cooperative.

(32) **Distributed resource** -- A generation, energy storage, or targeted demand-side resource, generally between one kilowatt and ten megawatts, located at a customer's site or near a load center, which may be connected at the distribution voltage level (below 60,000 volts), that provides advantages to the system, such as deferring the need for upgrading local distribution facilities.

(33) **Distribution service provider (DSP)** -- An electric utility, municipally-owned utility, or electric cooperative that owns or operates for compensation in this state equipment or facilities that are used for the distribution of electricity to retail customers, as defined in this section, including retail customers served at transmission voltage levels.

(34) **Economically distressed geographic area** -- Zip code area in which the average household income is less than or equal to 60% of the statewide median income, as reported in the most recently available United States Census data.

(35) **Electric cooperative --**

(A) a corporation organized under the Texas Utilities Code, Chapter 161 or a predecessor statute to Chapter 161 and operating under that chapter;

(B) a corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct affairs in the State of Texas; or

(C) a successor to an electric cooperative created before June 1, 1999, in accordance with a conversion plan approved by a vote of the members of the electric cooperative, regardless of whether the successor later purchases, acquires, merges with, or consolidates with other electric cooperatives.

(36) **Electric generating facility** -- A facility that generates electric energy for compensation and that is owned or operated by a person in this state, including a municipal corporation, electric cooperative, or river authority.

(37) **Electricity Facts Label** -- Information in a standardized format, as described in §25.475(f) of this title (relating to Information Disclosures to Residential and Small Commercial Customers), that summarizes the price, contract terms, fuel sources, and environmental impact associated with an electricity product.

(38) **Electricity product** -- A specific type of retail electricity service developed and identified by a REP, the specific terms and conditions of which are summarized in an Electricity Facts Label that is specific to that electricity product.

(39) **Electric Reliability Council of Texas (ERCOT)** -- Refers to the independent organization and, in a geographic sense, refers to the area served by electric utilities, municipally owned utilities, and electric cooperatives that are not synchronously interconnected with electric utilities outside of the State of Texas.

(40) **Electric service identifier (ESI ID)** -- The basic identifier assigned to each point of delivery used in the registration system and settlement system managed by the Electric Reliability Council of Texas (ERCOT) or another independent organization.

(41) **Electric utility --** Except as otherwise provided in this Chapter, an electric utility is: A person or river authority that owns or operates for compensation in this state equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in this state. The term includes a lessee, trustee, or receiver of an electric utility and a recreational vehicle park owner who does not comply with Texas Utilities Code, Subchapter C, Chapter 184, with regard to the metered sale of electricity at the recreational vehicle park. The term does not include:
(A) a municipal corporation;
(B) a qualifying facility;
(C) a power generation company;
(D) an exempt wholesale generator;
(E) a power marketer;
(F) a corporation described by Public Utility Regulatory Act §32.053 to the extent the corporation sells electricity exclusively at wholesale and not to the ultimate consumer;
(G) an electric cooperative;
(H) a retail electric provider;
(I) the state of Texas or an agency of the state; or
(J) a person not otherwise an electric utility who:
(i) furnishes an electric service or commodity only to itself, its employees, or its tenants as an incident of employment or tenancy, if that service or commodity is not resold to or used by others;
(ii) owns or operates in this state equipment or facilities to produce, generate, transmit, distribute, sell or furnish electric energy to an electric utility, if the equipment or facilities are used primarily to produce and generate electric energy for consumption by that person; or
(iii) owns or operates in this state a recreational vehicle park that provides metered electric service in accordance with Texas Utilities Code, Subchapter C, Chapter 184.

(42) **Energy efficiency** -- Programs that are aimed at reducing the rate at which electric energy is used by equipment and/or processes. Reduction in the rate of energy used may be obtained by substituting technically more advanced equipment to produce the same level of end-use services with less electricity; adoption of technologies and processes that reduce heat or other energy losses; or reorganization of processes to make use of waste heat. Efficient use of energy by customer-owned end-use devices implies that existing comfort levels, convenience, and productivity are maintained or improved at a lower customer cost.

(43) **Energy efficiency measures** -- Equipment, materials, and practices that when installed and used at a customer site result in a measurable and verifiable reduction in either purchased electric energy consumption, measured in kilowatt-hours (kWh), or peak demand, measured in kW, or both.

(44) **Energy efficiency project** -- An energy efficiency measure or combination of measures installed under a standard offer contract or a market transformation contract that results in both a reduction in customers' electric energy consumption and peak demand, and energy costs.

(45) **Energy efficiency service provider (EESP) --** A person who installs energy efficiency measures or performs other energy efficiency services. An energy

efficiency service provider may be a retail electric provider or large commercial customer, if the person has executed a standard offer contract.

(46) **Energy savings** -- A quantifiable reduction in a customer's consumption of energy.

(47) **ERCOT protocols** -- Body of procedures developed by ERCOT to maintain the reliability of the regional electric network and account for the production and delivery of electricity among resources and market participants. The procedures, initially approved by the commission, include a revisions process that may be appealed to the commission, and are subject to the oversight and review of the commission.

(48) **ERCOT region** -- The geographic area under the jurisdiction of the commission that is served by transmission service providers that are not synchronously interconnected with transmission service providers outside of the state of Texas.

(49) **Exempt wholesale generator** -- A person who is engaged directly or indirectly through one or more affiliates exclusively in the business of owning or operating all or part of a facility for generating electric energy and selling electric energy at wholesale who does not own a facility for the transmission of electricity, other than an essential interconnecting transmission facility necessary to effect a sale of electric energy at wholesale, and who is in compliance with the registration requirements of §25.109 of this title (Registration of Power Generation Companies and Self-Generators).

(50) **Existing purchased power contract** -- A purchased power contract in effect on January 1, 1999, including any amendments and revisions to that contract resulting from litigation initiated before January 1, 1999.

(51) **Facilities** -- All the plant and equipment of an electric utility, including all tangible and intangible property, without limitation, owned, operated, leased, licensed, used, controlled, or supplied for, by, or in connection with the business of an electric utility.

(52) **Financing order --** An order of the commission adopted under the Public Utility Regulatory Act §39.201 or §39.262 approving the issuance of transition bonds and the creation of transition charges for the recovery of qualified costs.

(53) **Freeze period --** The period beginning on January 1, 1999, and ending on December 31, 2001.

(54) **Generation assets --** All assets associated with the production of electricity, including generation plants, electrical interconnections of the generation plant to the transmission system, fuel contracts, fuel transportation contracts, water contracts, lands, surface or subsurface water rights, emissions-related allowances, and gas pipeline interconnections.

(55) **Generation service --** The production and purchase of electricity for retail customers and the production, purchase and sale of electricity in the wholesale power market.

(56) **Good utility practice --** Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather is intended to include acceptable practices, methods, and acts generally accepted in the region.

(57) **Hearing** -- Any proceeding at which evidence is taken on the merits of the matters at issue, not including prehearing conferences.

(58) **Independent organization** -- An independent system operator or other person that is sufficiently independent of any producer or seller of electricity that its decisions will not be unduly influenced by any producer or seller.

(59) **Independent system operator --** An entity supervising the collective transmission facilities of a power region that is charged with non-discriminatory coordination of market transactions, systemwide transmission planning, and network reliability.

(60) **Installed generation capacity** -- All potentially marketable electric generation capacity, including the capacity of:

(A) generating facilities that are connected with a transmission or distribution system;

(B) generating facilities used to generate electricity for consumption by the person owning or controlling the facility; and

(C) generating facilities that will be connected with a transmission or distribution system and operating within 12 months.

(61) **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.

(62) **License** -- The whole or part of any commission permit, certificate, approval, registration, or similar form of permission required by law.

(63) **Licensing** -- The commission process for granting, denial, renewal, revocation, suspension, annulment, withdrawal, or amendment of a license.

(64) **Load factor** -- The ratio of average load to peak load during a specific period of time, expressed as a percent. The load factor indicates to what degree energy has been consumed compared to maximum demand or utilization of units relative to total system capability.

(65) **Low-income customer** -- An electric customer who receives Supplemental Nutrition Assistance Program (SNAP) from Texas Health and Human Services Commission (HHSC) or medical assistance from a state agency administering a part of the medical assistance program.

(66) **Low-Income List Administrator (LILA)** -- A third-party administrator contracted by the commission to administer aspects of the low-income customer identification process established under PURA §17.007.

(67) **Market power mitigation plan --** A written proposal by an electric utility or a power generation company for reducing its ownership and control of installed generation capacity as required by the Public Utility Regulatory Act §39.154.

(68) **Market value --** For nonnuclear assets and certain nuclear assets, the value the assets would have if bought and sold in a bona fide third-party transaction or transactions on the open market under the Public Utility Regulatory Act (PURA) §39.262(h) or, for certain nuclear assets, as described by PURA §39.262(i), the value determined under the method provided by that subsection.

(69) **Master meter** -- A meter used to measure, for billing purposes, all electric usage of an apartment house or mobile home park, including common areas, common facilities, and dwelling units.

(70) **Municipality** -- A city, incorporated village, or town, existing, created, or organized under the general, home rule, or special laws of the state.

(71) **Municipally-owned utility (MOU)** -- Any utility owned, operated, and controlled by a municipality or by a nonprofit corporation whose directors are appointed by one or more municipalities.

(72) **Nameplate rating** -- The full-load continuous rating of a generator under specified conditions as designated by the manufacturer.

(73) **Native load customer --** A wholesale or retail customer on whose behalf an electric utility, electric cooperative, or municipally-owned utility, by statute, franchise, regulatory requirement, or contract, has an obligation to construct and operate its system to meet in a reliable manner the electric needs of the customer.

(74) **Natural gas energy credit (NGEC)** -- A tradable instrument representing each megawatt of new generating capacity fueled by natural gas, as authorized by the Public Utility Regulatory Act §39.9044 and implemented under §25.172 of this title (relating to Goal for Natural Gas).

(75) **Net book value** -- The original cost of an asset less accumulated depreciation.

(76) **Net dependable capability** -- The maximum load in megawatts, net of station use, which a generating unit or generating station can carry under specified conditions for a given period of time, without exceeding approved limits of temperature and stress.

(77) **New on-site generation** -- Electric generation capacity greater than ten megawatts capable of being lawfully delivered to the site without use of utility distribution or transmission facilities, which was not, on or before December 31, 1999, either:

(A) A fully operational facility, or

(B) A project supported by substantially complete filings for all necessary site-specific environmental permits under the rules of the Texas Natural Resource Conservation Commission (TNRCC) in effect at the time of filing.

(78) **Off-grid renewable generation --** The generation of renewable energy in an application that is not interconnected to a utility transmission or distribution system.

(79) **Other generation sources --** A competitive retailer’s or affiliated retail electric provider’s supply of generated electricity that is not accounted for by a direct supply contract with an owner of generation assets.

(80) **Person --** Includes an individual, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, and a corporation, but does not include an electric cooperative.

(81) **Power cost recovery factor (PCRF)** -- A charge or credit that reflects an increase or decrease in purchased power costs not in base rates.

(82) **Power generation company (PGC)** -- A person that:

(A) generates electricity that is intended to be sold at wholesale, including the owner or operator of electric energy storage equipment or facilities to which the Public Utility Regulatory Act, Chapter 35, Subchapter E applies;

(B) does not own a transmission or distribution facility in this state, other than an essential interconnecting facility, a facility not dedicated to public use, or a facility otherwise excluded from the definition of “electric utility” under this section; and

(C) does not have a certificated service area, although its affiliated electric utility or transmission and distribution utility may have a certificated service area.

(83) **Power marketer** -- A person who becomes an owner of electric energy in this state for the purpose of selling the electric energy at wholesale; does not own generation, transmission, or distribution facilities in this state; does not have a certificated service area; and who is in compliance with the registration

requirements of §25.105 of this title (relating to Registration and Reporting by Power Marketers).

(84) **Power region --** A contiguous geographical area which is a distinct region of the North American Electric Reliability Council.

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

(86) **Premises** -- A tract of land or real estate or related commonly used tracts including buildings and other appurtenances thereon.

(87) **Price to beat (PTB) --** A price for electricity, as determined pursuant to the Public Utility Regulatory Act §39.202, charged by an affiliated retail electric provider to eligible residential and small commercial customers in its service area.

(88) **Proceeding** -- A hearing, investigation, inquiry, or other procedure for finding facts or making a decision. The term includes a denial of relief or dismissal of a complaint. It may be rulemaking or nonrulemaking; rate setting or non-rate setting.

(89) **Proprietary customer information** -- Any information compiled by a retail electric provider, an electric utility, a transmission and distribution business unit as defined in §25.275(c)(16) of this title (relating to Code of Conduct for Municipally Owned Utilities and Electric Cooperatives Engaged in Competitive Activities) on a customer in the course of providing electric service or by an aggregator on a customer in the course of aggregating electric service that makes possible the identification of any individual customer by matching such information with the customer's name, address, account number, type or classification of service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges, billing records, or any information that the customer has expressly requested not be disclosed. Information that is redacted or organized in such a way as to make it impossible to identify the customer to whom the information relates does not constitute proprietary customer information.

(90) **Provider of last resort (POLR)** -- A retail electric provider (REP) certified in Texas that has been designated by the commission to provide a basic, standard retail service package in accordance with §25.43 of this title (relating to Provider of Last Resort (POLR)).

(91) **Public retail customer** -- A retail customer that is an agency of this state, a state institution of higher education, a public school district, or a political subdivision of this state.

(92) **Public utility or utility --** An electric utility as that term is defined in this section, or a public utility or utility as those terms are defined in the Public Utility Regulatory Act §51.002.

(93) **Public Utility Regulatory Act (PURA)** -- The enabling statute for the Public Utility Commission of Texas, located in the Texas Utilities Code Annotated, §§11.001 *et. seq*.

(94) **Purchased power market value --** The value of demand and energy bought and sold in a bona fide third-party transaction or transactions on the open market and determined by using the weighted average costs of the highest three offers from the market for purchase of the demand and energy available under the existing purchased power contracts.

(95) **Qualified scheduling entity** -- A market participant that is qualified by the Electric Reliability Council of Texas (ERCOT) in accordance with Section 16, Registration and Qualification of Market Participants of ERCOT's Protocols, to submit balanced schedules and ancillary services bids and settle payments with ERCOT.

(96) **Qualifying cogenerator** -- The meaning as assigned this term by 16 U.S.C. §796(18)(C). A qualifying cogenerator that provides electricity to the purchaser of the cogenerator's thermal output is not for that reason considered to be a retail electric provider or a power generation company.

(97) **Qualifying facility** -- A qualifying cogenerator or qualifying small power producer.

(98) **Qualifying small power producer** -- The meaning as assigned this term by 16 U.S.C. §796(17)(D).

(99) **Rate** -- A compensation, tariff, charge, fare, toll, rental, or classification that is directly or indirectly demanded, observed, charged, or collected by an electric utility for a service, product, or commodity described in the definition of electric utility in this section and a rule, practice, or contract affecting the compensation, tariff, charge, fare, toll, rental, or classification that must be approved by a regulatory authority.

(100) **Rate class --** A group of customers taking electric service under the same rate schedule.

(101) **Rate year** -- The 12-month period beginning with the first date that rates become effective. The first date that rates become effective may include, but is not limited to, the effective date for bonded rates or the effective date for interim or temporary rates.

(102) **Ratemaking proceeding --** A proceeding in which a rate may be changed.

(103) **Registration agent** -- Entity designated by the commission to administer registration and settlement, premise data, and other processes concerning a customer's choice of retail electric provider in the competitive electric market in Texas.

(104) **Regulatory authority** -- In accordance with the context where it is found, either the commission or the governing body of a municipality.

(105) **Renewable demand side management (DSM) technologies** -- Equipment that uses a renewable energy resource (renewable resource) as defined in this section, that, when installed at a customer site, reduces the customer's net purchases of energy (kWh), electrical demand (kW), or both.

(106) **Renewable energy --** Energy derived from renewable energy technologies.

(107) **Renewable energy credit (REC) --** A tradable instrument representing the generation attributes of one MWh of electricity from renewable energy sources, as authorized by the Public Utility Regulatory Act §39.904 and implemented under §25.173(e) of this title (relating to Goal for Renewable Energy).

(108) **Renewable energy credit account (REC account) --** An account maintained by the renewable energy credits trading program administrator for the purpose of tracking the production, sale, transfer, purchase, and retirement of RECs by a program participant.

(109) **Renewable energy resource (renewable resource) --** A resource that produces energy derived from renewable energy technologies.

(110) **Renewable energy technology** -- Any technology that exclusively relies on an energy source that is naturally regenerated over a short time and derived directly from the sun, indirectly from the sun or from moving water or other natural movements and mechanisms of the environment. Renewable energy technologies

include those that rely on energy derived directly from the sun, on wind, geothermal, hydroelectric, wave, or tidal energy, or on biomass or biomass-based waste products, including landfill gas. A renewable energy technology does not rely on energy resources derived from fossil fuels, waste products from fossil fuels, or waste products from inorganic sources.

(111) **Repowering --** Modernizing or upgrading an existing facility in order to increase its capacity or efficiency.

(112) **Residential customer** -- Retail customers classified as residential by the applicable bundled utility tariff, unbundled transmission and distribution utility tariff or, in the absence of classification under a residential rate class, those retail customers that are primarily end users consuming electricity at the customer's place of residence for personal, family or household purposes and who are not resellers of electricity.

(113) **Retail customer --** The separately metered end-use customer who purchases and ultimately consumes electricity.

(114) **Retail electric provider (REP) --** A person that sells electric energy to retail customers in this state. A retail electric provider may not own or operate generation assets.

(115) **Retail stranded costs -- T**hat part of net stranded cost associated with the provision of retail service.

(116) **Retrofit** -- The installation of control technology on an electric generating facility to reduce the emissions of nitrogen oxide, sulfur dioxide, or both.

(117) **River authority** -- A conservation and reclamation district created pursuant to the Texas Constitution, Article 16, Section 59, including any nonprofit corporation created by such a district pursuant to the Texas Water Code, Chapter 152, that is an electric utility.

(118) **Rule** -- A statement of general applicability that implements, interprets, or prescribes law or policy, or describes the procedure or practice requirements of the commission. The term includes the amendment or repeal of a prior rule, but does not include statements concerning only the internal management or organization of the commission and not affecting private rights or procedures.

(119) **Separately metered --** Metered by an individual meter that is used to measure electric energy consumption by a retail customer and for which the customer is directly billed by a utility, retail electric provider, electric cooperative, or municipally owned utility.

(120) **Service** -- Has its broadest and most inclusive meaning. The term includes any act performed, anything supplied, and any facilities used or supplied by an electric utility in the performance of its duties under the Public Utility Regulatory Act to its patrons, employees, other public utilities or electric utilities, an electric cooperative, and the public. The term also includes the interchange of facilities between two or more public utilities or electric utilities.

(121) **Spanish-speaking person --** A person who speaks any dialect of the Spanish language exclusively or as their primary language.

(122) **Standard meter** -- The minimum metering device necessary to obtain the billing determinants required by the transmission and distribution utility's tariff schedule to determine an end-use customer's charges for transmission and distribution service.

(123) **Stranded cost --** The positive excess of the net book value of generation assets over the market value of the assets, taking into account all of the electric utility's generation assets, any above-market purchased power costs, and any deferred debit related to a utility's discontinuance of the application of Statement of

Financial Accounting Standards Number 71 ("Accounting for the Effect of Certain Types of Regulation") for generation-related assets if required by the provisions of the Public Utility Regulatory Act (PURA), Chapter 39. For purposes of PURA §39.262, book value shall be established as of December 31, 2001, or the date a market value is established through a market valuation method under PURA §39.262(h), whichever is earlier, and shall include stranded costs incurred under PURA §39.263.

(124) **Submetering --** Metering of electricity consumption on the customer side of the point at which the electric utility meters electricity consumption for billing purposes.

(125) **Summer net dependable capability --** The net capability of a generating unit in megawatts (MW) for daily planning and operational purposes during the summer peak season, as determined in accordance with requirements of the reliability council or independent organization in which the unit operates.

(126) **Supply-side resource** -- A resource, including a storage device, that provides electricity from fuels or renewable resources.

(127) **System emergency --** A condition on a utility's system that is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(128) **Tariff** -- The schedule of a utility, municipally-owned utility, or electric cooperative containing all rates and charges stated separately by type of service, the rules and regulations of the utility, and any contracts that affect rates, charges, terms or conditions of service.

(129) **Termination of service** -- The cancellation or expiration of a sales agreement or contract by a retail electric provider by notification to the customer and the registration agent.

(130) **Tenant** -- A person who is entitled to occupy a dwelling unit to the exclusion of others and who is obligated to pay for the occupancy under a written or oral rental agreement.

(131) **Test year** -- The most recent 12 months for which operating data for an electric utility, electric cooperative, or municipally-owned utility are available and shall commence with a calendar quarter or a fiscal year quarter.

(132) **Texas jurisdictional installed generation capacity** -- The amount of an affiliated power generation company's installed generation capacity properly allocable to the Texas jurisdiction. Such allocation shall be calculated pursuant to an existing commission-approved allocation study, or other such commission-approved methodology, and may be adjusted as approved by the commission to reflect the effects of divestiture or the installation of new generation facilities.

(133) **Transition bonds** -- Bonds, debentures, notes, certificates, of participation or of beneficial interest, or other evidences of indebtedness or ownership that are issued by an electric utility, its successors, or an assignee under a financing order, that have a term not longer than 15 years, and that are secured or payable from transition property.

(134) **Transition charges** -- Non-bypassable amounts to be charged for the use or availability of electric services, approved by the commission under a financing order to recover qualified costs, that shall be collected by an electric utility, its successors, an assignee, or other collection agents as provided for in a financing order.

(135) **Transmission and distribution business unit (TDBU)** -- The business unit of a municipally owned utility/electric cooperative, whether structurally unbundled as a separate legal entity or functionally unbundled as a division, that owns or operates

for compensation in this state equipment or facilities to transmit or distribute electricity at retail, except for facilities necessary to interconnect a generation facility with the transmission or distribution network, a facility not dedicated to public use, or a facility otherwise excluded from the definition of electric utility in a qualifying power region certified under the Public Utility Regulatory Act §39.152. Transmission and distribution business unit does not include a municipally owned utility/electric cooperative that owns, controls, or is an affiliate of the transmission and distribution business unit if the transmission and distribution business unit is organized as a separate corporation or other legally distinct entity. Except as specifically authorized by statute, a transmission and distribution business unit shall not provide competitive energy-related activities.

(136) **Transmission and distribution utility (TDU) --** A person or river authority that owns, or operates for compensation in this state equipment or facilities to transmit or distribute electricity, except for facilities necessary to interconnect a generation facility with the transmission or distribution network, a facility not dedicated to public use, or a facility otherwise excluded from the definition of "electric utility", in a qualifying power region certified under the Public Utility Regulatory Act (PURA) §39.152, but does not include a municipally owned utility or an electric cooperative. The TDU may be a single utility or may be separate transmission and distribution utilities.

(137) **Transmission line** -- A power line that is operated at 60 kilovolts (kV) or above, when measured phase-to-phase.

(138) **Transmission service --** Service that allows a transmission service customer to use the transmission and distribution facilities of electric utilities, electric cooperatives and municipally owned utilities to efficiently and economically utilize generation resources to reliably serve its loads and to deliver power to another transmission service customer. Includes construction or enlargement of facilities, transmission over distribution facilities, control area services, scheduling resources, regulation services, reactive power support, voltage control, provision of operating reserves, and any other associated electrical service the commission determines appropriate, except that, on and after the implementation of customer choice in any portion of the Electric Reliability Council of Texas (ERCOT) region, control area services, scheduling resources, regulation services, provision of operating reserves, and reactive power support, voltage control and other services provided by generation resources are not "transmission service".

(139) **Transmission service customer** -- A transmission service provider, distribution service provider, river authority, municipally-owned utility, electric cooperative, power generation company, retail electric provider, federal power marketing agency, exempt wholesale generator, qualifying facility, power marketer, or other person whom the commission has determined to be eligible to be a transmission service customer. A retail customer, as defined in this section, may not be a transmission service customer.

(140) **Transmission service provider (TSP) --** An electric utility, municipally-owned utility, or electric cooperative that owns or operates facilities used for the transmission of electricity.

(141) **Transmission system** -- The transmission facilities at or above 60 kilovolts (kV) owned, controlled, operated, or supported by a transmission service provider or transmission service customer that are used to provide transmission service.

§25.6. Cost of Copies of Public Information.

The rules set forth in 1 TAC §§70.3 (relating to Costs of Copies of Public Information) will apply to copies of public records made at the commission.

§25.8. Classification System for Violations of Statutes, Rules, and Orders Applicable to Electric Service Providers.

(a) **Purpose.** The purpose of this rule is to establish a classification system for violations of the Public Utility Regulatory Act (PURA) and related commission rules and orders, and to establish a range of penalties that may be assessed for each class of violations.

(b) **Classification system.**

(1) **Class C violations.**

(A) Penalties for Class C violations may not exceed $1,000 per violation per day.

(B) The following violations are Class C violations:

(i) failure to file a report or provide information required to be submitted to the commission under this chapter within the timeline required;

(ii) failure by an electric utility, retail electric provider, or aggregator to investigate a customer complaint and appropriately report the results within the timeline required;

(iii) failure to update information relating to a registration or certificate by the commission within the timeline required; and

(iv) a violation of the Electric no-call list.

(2) **Class B violations.**

(A) Penalties for Class B violations may not exceed $5,000 per violation per day.

(B) All violations not specifically enumerated as a Class C or Class A violation shall be considered Class B violations.

(3) **Class A violations.**

(A) Penalties for Class A violations may not exceed $25,000 per violation per day.

(B) The following types of violations are Class A violations if they create economic harm in excess of $5,000 to a person or persons, property, or the environment, or create an economic benefit to the violator in excess of $5,000; create a hazard or potential hazard to the health or safety of the public; or cause a risk to the reliability of a transmission or distribution system or a portion thereof.

(i) A violation related to the wholesale electric market, including protocols and other requirements established by an independent organization;

(ii) A violation related to electric service quality standards or reliability standards established by the commission or an independent organization;

(iii) A violation related to the code of conduct between electric utilities and their competitive affiliates;

(iv) A violation related to prohibited discrimination in the provision of electric service;

(v) A violation related to improper disconnection of electric service;

(vi) A violation related to fraudulent, unfair, misleading, deceptive, or anticompetitive business practices;

(vii) Conducting business subject to the jurisdiction of the commission without proper commission authorization, registration, licensing, or certification;

(viii) A violation committed by ERCOT;

(ix) A violation not otherwise enumerated in this paragraph (3)(B) of this subsection that creates a hazard or potential hazard to the health or safety of the public;

(x) A violation not otherwise enumerated in this paragraph (3)(B) of this subsection that creates economic harm to a person or persons, property, or the environment in excess of $5,000, or creates an economic benefit to the violator in excess of $5,000; and

(xi) A violation not otherwise enumerated in this paragraph (3)(B) of this subsection that causes a risk to the reliability of a transmission or distribution system or a portion thereof.

(c) **Application of enforcement provisions of other rules.** To the extent that PURA or other rules in this chapter establish a range of administrative penalties that are inconsistent with the penalty ranges provided for in subsection (b) of this section, the other provisions control with respect to violations of those rules.

(d) **Assessment of administrative penalties.** In addition to the requirements of §22.246 of this title (relating to Administrative Penalties), a notice of violation recommending administrative penalties shall indicate the class of violation.

§25.21. General Provisions of Customer Service and Protection Rules.

(a) **Application.** Unless the context clearly indicates otherwise, in this subchapter the term "electric utility" applies to all electric utilities that provide retail electric utility service in Texas. It does not apply to municipal utilities.

(b) **Purpose.** The purpose of the rules in this subchapter is to establish minimum customer service standards that electric utilities must follow in providing electric service to the public. Nothing in these rules should be interpreted as preventing an electric utility from adopting less restrictive policies for all customers or for differing groups of customers, as long as those policies do not discriminate based on race, color, sex, nationality, religion, or marital status.

(c) **Definitions.** The following words and terms when used in this subchapter shall have the following meanings, unless the context indicates otherwise.

(1) **Applicant--**A person who applies for service for the first time or reapplies after disconnection of service.

(2) **Burned Veteran**--A customer who is a military veteran who a medical doctor certifies has a significantly decreased ability to regulate the body temperature because of severe burns received in combat.

(3) **Customer--**A person who is currently receiving service from an electric utility in the person’s own name or the name of the person’s spouse.

(4) **Days--**Unless the context clearly indicates otherwise, in this subchapter the term “days” shall refer to calendar days.

§25.22. Request for Service.

Every electric utility shall initiate service to each qualified applicant for service within its certificated area in accordance with this section.

(1) Applications for new electric service not involving line extensions or construction of new facilities shall be filled within seven working days after the applicant has met the credit requirements as provided for in §25.24 of this title (relating to Credit Requirements and Deposits) and complied with all applicable state and municipal regulations.

(2) An electric utility may require a residential applicant for service to satisfactorily establish credit in accordance with §25.24 of this title (relating to Credit Requirements and Deposits), but such establishment of credit shall not relieve the customer from complying with rules for prompt payment of bills.

(3) Requests for new residential service requiring construction, such as line extensions, shall be completed within 90 days or within a time period agreed to by the customer and electric utility if the applicant has met the credit requirements as provided for in §25.24 of this title; and made satisfactory payment arrangements for construction charges; and has complied with all applicable state and municipal regulations. For this section, facility placement which requires a permit for a road or railroad crossing will be considered a line extension.

(4) If facilities must be constructed, then the electric utility shall contact the customer within 10 working days of receipt of the application, and give the customer an estimated completion date and an estimated cost for all charges to be incurred by the customer.

(5) The electric utility shall explain any construction cost options such as rebates to the customer, sharing of construction costs between the electric utility and the customer, or sharing of costs between the customer and other applicants following the assessment of necessary line work.

(6) Unless the delay is beyond the reasonable control of the electric utility, a delay of more than 90 days shall constitute failure to serve, unless the customer and electric utility have agreed to a longer term. The commission may revoke or amend an electric utility's certificate of convenience and necessity (or other certificate) for such failures to serve, or grant the certificate to another electric utility to serve the applicant, and the electric utility may be subject to administrative penalties pursuant to the Public Utility Regulatory Act §15.023 and §15.024.

(7) If an electric utility must provide a line extension to or on the customer's premises and the utility will require that customer to pay a Contribution in Aid to Construction (CIAC), a prepayment, or sign a contract with a term of one year or longer, the electric utility shall provide the customer with information about on-site renewable energy and distributed generation technology alternatives. The information shall comply with guidelines established by the commission, and shall be provided to the customer at the time the estimate of the CIAC or prepayment is given to the customer. If no CIAC or prepayment is required, the information shall be given to the customer before a contract is signed. The information is intended to educate the customer on alternate options that are available.

(8) As part of their initial contact, electric utility employees shall give the applicant a copy of the "Your Rights as a Customer" brochure, and inform an applicant of the right to file a complaint with the commission pursuant to §25.30 of this title (relating to complaints) if the applicant thinks the applicant has been treated unfairly.

§25.23. Refusal of Service.

(a) **Acceptable reasons to refuse service.** An electric utility may refuse to serve an applicant until the applicant complies with state and municipal regulations and the utility's rules and regulations on file with the commission or for any of the reasons identified below.

(1) **Applicant's facilities inadequate.** The applicant's installation or equipment is known to be hazardous or of such character that satisfactory service cannot be given, or the applicant's facilities do not comply with all applicable state and municipal regulations.

(2) **Violation of an electric utility's tariffs.** The applicant fails to comply with the electric utility's tariffs pertaining to operation of nonstandard equipment or unauthorized attachments which interfere with the service of others. The electric utility shall provide the applicant notice of such refusal and afford the applicant a reasonable amount of time to comply with the utility's tariffs.

(3) **Failure to pay guarantee.** The applicant has acted as a guarantor for another customer and failed to pay the guaranteed amount, where such guarantee was made in writing to the electric utility and was a condition of service.

(4) **Intent to deceive.** The applicant applies for service at a location where another customer received, or continues to receive, service and the electric utility bill is unpaid at that location, and the electric utility can prove the change in identity is made in an attempt to help the other customer avoid or evade payment of an electric utility bill. An applicant may request a supervisory review as specified in §25.30 of this title (relating to Complaints) if the electric utility determines that the applicant intends to deceive the electric utility and refuses to provide service.

(5) **For indebtedness.** The applicant owes a debt to any electric utility for the same kind of service as that being requested. In the event an applicant's indebtedness is in dispute, the applicant shall be provided service upon paying a deposit pursuant to §25.24 of this title (relating to Credit Requirements and Deposits).

(6) **Refusal to pay a deposit.** Refusing to pay a deposit if applicant is required to do so under §25.24 of this title.

(b) **Applicant's recourse.** If an electric utility has refused to serve an applicant under the provisions of this section, the electric utility must inform the applicant of the reason for its refusal and that the applicant may file a complaint with the commission as described in §25.30 of this title.

(c) **Insufficient grounds for refusal to serve.** The following are not sufficient cause for refusal of service to an applicant:

(1) delinquency in payment for service by a previous occupant of the premises to be served;

(2) failure to pay for merchandise or charges for non-regulated services, including but not limited to insurance policies, Internet service, or home security services, purchased from the electric utility;

(3) failure to pay a bill that includes more than the allowed six months of underbilling, unless the underbilling is the result of theft of service; or

(4) failure to pay the bill of another customer at the same address except where the change in identity is made to avoid or evade payment of an electric utility bill.

§25.24. Credit Requirements and Deposits.

(a) **Credit requirements for permanent residential applicants.**

(1) An electric utility may require a residential applicant for service to establish and maintain satisfactory credit as a condition of providing service.

(A) Establishment of credit shall not relieve any customer from complying with the electric utility's requirements for prompt payment of bills.

(B) The credit worthiness of spouses established during shared service in the 12 months prior to their divorce will be equally applied to both spouses for 12 months immediately after their divorce.

(2) A residential applicant can demonstrate satisfactory credit using any one of the criteria listed in subparagraphs (A) through (C) of this paragraph.

(A) The residential applicant:

(i) has been a customer of any electric utility for the same kind of service within the last two years;

(ii) is not delinquent in payment of any such electric utility service account;

(iii) during the last 12 consecutive months of service was not late in paying a bill more than once;

(iv) did not have service disconnected for nonpayment; and

(v) is encouraged to obtain a letter of credit history from the applicant's previous electric utility, and electric utilities are encouraged to provide such information with the final bill.

(B) The residential applicant demonstrates a satisfactory credit rating by appropriate means, including, but not limited to, the production of:

(i) generally acceptable credit cards;

(ii) letters of credit reference;

(iii) the names of credit references which may be quickly and inexpensively contacted by the electric utility; or

(iv) ownership of substantial equity that is easily liquidated.

(C) The residential applicant is 65 years of age or older and does not have an outstanding account balance incurred within the last two years with the electric utility or another electric utility for the same type of utility service.

(3) If satisfactory credit cannot be demonstrated by the residential applicant using these criteria, the applicant may be required to pay a deposit pursuant to subsection (c) of this section.

(b) **Credit requirements for non-residential applicants.** For non-residential service, if an applicant's credit has not been demonstrated satisfactorily to the electric utility, the applicant may be required to pay a deposit.

(c) **Initial deposits.**

(1) A residential applicant or customer who is required to pay an initial deposit may provide the electric utility with a written letter of guarantee pursuant to subsection (j) of this section, instead of paying a cash deposit.

(2) An initial deposit may not be required from an existing customer unless the customer was late paying a bill more than once during the last 12 months of service or had service disconnected for nonpayment. The customer may be required to pay this initial deposit within ten days after issuance of a written termination notice that requests such deposit. Instead of an initial deposit, the customer may pay the total amount due on the current bill by the due date of the bill, provided the customer has not exercised this option in the previous 12 months.

(d) **Additional deposits.**

(1) An additional deposit may be required if:

(A) the average of the customer's actual billings for the last 12 months are at least twice the amount of the original estimated annual billings; and

(B) a disconnection notice has been issued for the account within the previous 12 months.

(2) An electric utility may require that an additional deposit be paid within ten days after the electric utility has issued a written disconnection notice and requested the additional deposit.

(3) Instead of an additional deposit, the customer may pay the total amount due on the current bill by the due date of the bill, provided the customer has not exercised this option in the previous 12 months.

(4) The electric utility may disconnect service if the additional deposit is not paid within ten days of the request, provided a written disconnection notice has been issued to the customer. A disconnection notice may be issued concurrently with either the written request for the additional deposit or current usage payment.

(e) **Deposits for temporary or seasonal service and for weekend residences.** The electric utility may require a deposit sufficient to reasonably protect it against the assumed risk for temporary or seasonal service or weekend residences, as long as the policy is applied in a uniform and nondiscriminatory manner. These deposits shall be returned according to guidelines set out in subsection (k) of this section.

(f) **Amount of deposit.** The total of all deposits shall not exceed an amount equivalent to one-sixth of the estimated annual billing.

(g) **Interest on deposits.** Each electric utility requiring deposits shall pay interest on these deposits at an annual rate at least equal to that set by the commission on or before December 1 of the preceding calendar year, pursuant to Texas Utilities Code §183.003 (relating to Rate of Interest). If a deposit is refunded within 30 days of the date of deposit, no interest payment is required. If the electric utility keeps the deposit more than 30 days, payment of interest shall be made retroactive to the date of deposit.

(1) Payment of the interest to the customer shall be made annually, if requested by the customer, or at the time the deposit is returned or credited to the customer's account.

(2) The deposit shall cease to draw interest on the date it is returned or credited to the customer's account.

(h) **Notification to customers.** When a deposit is required, the electric utility shall provide the applicant or customer written information about deposits by providing the "Your Rights as a Customer" brochure, which contains the relevant information.

(i) **Records of deposits.**

(1) The electric utility shall keep records to show:

(A) the name and address of each depositor;

(B) the amount and date of the deposit; and

(C) each transaction concerning the deposit.

(2) The electric utility shall issue a receipt of deposit to each applicant paying a deposit and shall provide means for a depositor to establish a claim if the receipt is lost.

(3) A record of each unclaimed deposit must be maintained for at least four years.

(4) The electric utility shall make a reasonable effort to return unclaimed deposits.

(j) **Guarantees of residential customer accounts.**

(1) A guarantee agreement between an electric utility and a guarantor must be in writing and shall be for no more than the amount of deposit the electric utility would require on the applicant's account pursuant to subsection (f) of this section. The amount of the guarantee shall be clearly indicated in the signed agreement.

(2) The guarantee shall be voided and returned to the guarantor according to the provisions of subsection (k) of this section.

(3) Upon default by a residential customer, the guarantor of that customer's account shall be responsible for the unpaid balance of the account only up to the amount agreed to in the written agreement.

(4) The electric utility shall provide written notification to the guarantor of the customer's default, the amount owed by the guarantor, and the due date for the amount owed.

(A) The electric utility shall allow the guarantor 16 days from the date of notification to pay the amount owed on the defaulted account. If the sixteenth day falls on a holiday or weekend, the due date shall be the next workday.

(B) The electric utility may transfer the amount owed on the defaulted account to the guarantor's own service bill provided the guaranteed amount owed is identified separately on the bill as required by §25.25(c)(10) of this title (relating to the Issuance and Format of Bills).

(5) The electric utility may disconnect service to the guarantor for nonpayment of the guaranteed amount only if the disconnection was included in the terms of the written agreement, and only after proper notice as described by paragraph (4) of this subsection, and §25.29(b)(5) of this title (relating to Disconnection of Service).

(k) **Refunding deposits and voiding letters of guarantee.**

(1) If service is not connected, or is disconnected, the electric utility shall promptly void and return to the guarantor all letters of guarantee on the account or provide written documentation that the contract has been voided, or refund the customer's deposit plus accrued interest on the balance, if any, in excess of the unpaid bills for service furnished. A transfer of service from one premise to another within the service area of the electric utility is not a disconnection, and no additional deposit may be required.

(2) When the customer has paid bills for service for 12 consecutive residential billings or for 24 consecutive non-residential billings without having service disconnected for nonpayment of a bill and without having more than two occasions in which a bill was delinquent, and when the customer is not delinquent in the payment of the current bills, the electric utility shall promptly refund the deposit plus accrued interest to the customer, or void and return the guarantee or provide written documentation that the contract has been voided. If the customer does not meet these refund criteria, the deposit and interest or the letter of guarantee may be retained.

(l) **Re-establishment of credit.** Every applicant who previously has been a customer of the electric utility and whose service has been disconnected for nonpayment of bills or theft of service (meter tampering or bypassing of meter) shall be required, before service is reconnected, to pay all amounts due the utility or execute a deferred payment agreement, if offered, and reestablish credit. The electric utility must prove the amount of utility service received but not paid for and the reasonableness of any charges for the unpaid service, and any other charges required to be paid as a condition of service restoration.

(m) **Upon sale or transfer of utility or company.** Upon the sale or transfer of any electric utility or any of its operating units, the seller shall provide the buyer all required deposit records.

§25.25. Issuance and Format of Bills.

(a) **Frequency of bills.** An electric utility shall issue bills monthly, unless otherwise authorized by the Public Utility Commission, or unless service is provided for a period less than one month. Bills shall be issued as promptly as possible after reading meters.

(b) **Billing information.** The electric utility shall provide free to the customer a breakdown of charges at the time the service is initially installed or modified and upon request by the customer as well as the applicable rate schedule.

(c) **Bill content.** Each customer's bill shall include all the following information:

(1) if the meter is read by the electric utility, the date and reading of the meter at the beginning and at the end of the billing period;

(2) the due date of the bill, as specified in §25.28 of this title (relating to Bill Payment and Adjustments);

(3) the number and kind of units metered;

(4) the applicable rate schedule and title or code should be provided upon request by the customer;

(5) the total amount due after addition of any penalty for nonpayment within a designated period. The terms "gross bill" and "net bill" or other similar terms implying the granting of a discount for prompt payment shall be used only when an actual discount for prompt payment is granted. The terms shall not be used when a penalty is added for nonpayment within a designated period;

(6) the word "Estimated" prominently displayed to identify an estimated bill;

(7) any conversions from meter reading units to billing units, or any other calculations to determine billing units from recording or other devices, or any other factors used in determining the bill; and

(8) any amount owed under a written guarantee contract provided the guarantor was previously notified in writing by the electric utility as required by §25.24 of this title (relating to Credit Requirements and Deposits).

(9) To the extent that a utility applies a charge to the customer's bill that is consistent with one of the terms set out in this paragraph, the term shall be used in identifying charges on customer's bills, and the definitions in this paragraph shall be easily located on the utility's website. A utility may not use a different term for a charge that is defined in this paragraph.

(A) Advanced metering charge -- A charge to recover the costs of an advanced metering system;

(B) Energy Charge -- Any charge, other than a tax or other fee, that is assessed on the basis of the customer's energy consumption.

(C) Energy Efficiency Cost Recovery Factor -- A charge approved by the Public Utility Commission to recover the electric utility's cost of providing energy efficiency programs.

(D) Fuel Charge -- A charge approved by the Public Utility Commission for the recovery of the utility's costs for the fuel used to generate electricity.

(E) Meter Number -- The number assigned by the utility to the customer's meter.

(F) Meter Charge -- A charge approved by the Public Utility Commission for metering a customer's consumption.

(G) Miscellaneous Gross Receipts Fee -- A fee assessed to recover the miscellaneous gross receipts tax imposed on utilities operating in an incorporated city or town having a population of more than 1,000.

(H) Municipal Franchise Fee -- A fee assessed to compensate municipalities for the utility's use of public rights-of-way.

(I) Nuclear Decommissioning Fee -- A charge approved by the Public Utility Commission to provide funds for decommissioning of nuclear generating sites.

(J) PUC Assessment -- A fee assessed to recover the statutory fee for administering the Public Utility Regulatory Act.

(K) Sales tax -- Sales tax collected by authorized taxing authorities, such as the state, cities, and special purpose districts.

(10) To the extent that a utility uses the concepts identified in this paragraph in a customer's bill, it shall use the term set out in this paragraph, and the definitions in this paragraph shall be easily located on the utility's website. A utility may not use a different term for a charge that is defined in this paragraph.

(A) Current Meter Read -- The meter reading at the end of the period for which the customer is being billed;

(B) kW -- Kilowatt, the standard unit for measuring electricity demand, equal to 1,000 watts;

(C) kWh -- Kilowatt-hour, the standard unit for measuring electricity energy consumption, equal to 1.000 watt-hours; and

(D) Previous Meter Read -- The reading on the beginning the period for which the customer is being billed.

(d) **Estimated bills.**

(1) An electric utility may submit estimated bills for good cause provided that an actual meter reading is taken no less than every third month. In months where the meter reader is unable to gain access to the premises to read the meter on regular meter reading trips, or in months when meters are not read, the electric utility must provide the customer with a postcard and request the customer to read the meter and return the card to the electric utility. If the postcard is not received by the electric utility in time for billing, the electric utility may estimate the meter reading and issue a bill.

(2) If an electric utility has a program in which customers read their own meters and report their usage monthly and no meter reading is submitted by a customer the electric utility may estimate the customer's usage and issue a bill. However, the electric utility must read the meter if the customer does not submit readings for three consecutive months so that a corrected bill may be issued.

(e) **Record retention.** Each electric utility shall maintain monthly billing records for each account for at least two years after the date the bill is mailed. The billing records shall contain sufficient data to reconstruct a customer's billing for a given month. Copies of a customer's billing records may be obtained by that customer on request.

(f) **Transfer of delinquent balances**. If the customer has an outstanding balance due from another account in the same customer class, then the utility may transfer that balance to the customer's current account. The delinquent balance and specific account shall be identified as such on the bill.

§25.26. Spanish Language Requirements.

(a) **Application.** This section applies to each electric utility that serves a county where the number of Spanish speaking persons as defined in §25.5 of this title (relating to Definitions) is 2000 or more according to the most current U.S. Census of Population (Bureau of Census, U.S. Department of Commerce, Census of Population and Housing).

(b) **Written plan.**

(1) **Requirement.** Each electric utility shall have a commission-approved written plan that describes how a Spanish-speaking person is provided, or will be provided, reasonable access to the utility's programs and services.

(2) **Minimum elements.** The written plan required by paragraph (1) of this subsection shall include a clear and concise statement as to how the electric utility is doing or will do the following, for each part of its entire system:

(A) inform Spanish-speaking applicants how they can get information contained in the utility's plan in the Spanish language;

(B) inform Spanish-speaking applicants and customers of their rights contained in this subchapter;

(C) inform Spanish-speaking applicants and customers of new services, discount programs, and promotions;

(D) allow Spanish-speaking persons to request repair service;

(E) ballot Spanish-speaking customers for services requiring a vote by ballot;

(F) allow access by Spanish-speaking customers to services specified in subchapter F of this chapter (relating to Metering);

(G) inform its service and repair representatives of the requirements of the plan.

§25.27. Retail Electric Service Switchovers.

(a) **Right to switchover.**

(1) **General principles.** A consumer has the right to switch retail electric service to any electric or municipally owned utility that has the right to provide service in the area in which the consumer's consuming facility is located, subject to the terms of any contract for electric service entered into pursuant to the disconnecting utility's tariff. Because a consuming facility for which a switchover is sought can obtain electric service from the disconnecting utility prior to the switchover, an electric or municipally owned utility shall give a switchover a lower priority than the elimination of outages and requests for service to consuming facilities that do not have service. Nevertheless, a switchover shall be performed as soon as reasonably possible, and the disconnecting and connecting utilities shall strive to take the actions required below more quickly than the deadlines listed below. In addition, the disconnecting and connecting utilities shall minimize any outages related to making a switchover.

(2) **Options and availability.** This section provides two switchover options: partial switchover and full switchover. All subsections of this section apply to electric utilities, while only subsections (a), (c), (e), and (g) of this section apply to municipally owned utilities. The partial switchover option is not available in a particular area prior to September 1, 1999 and prior to such time as both the disconnecting and connecting utilities have approved tariffs for transmission service at the transmission and primary and secondary distribution voltage levels. Until the utilities have such approved tariffs, subsections (d) and (e) of this section do not apply. In addition, the partial switchover option is not available to the extent that it would reduce the state's jurisdiction over a utility. The provisions for full switchovers in this section become effective for a particular area once the electric utilities that have a right to provide service in the area have tariffs in effect that are consistent with this section.

(3) **Limitations and refunds.** A consuming facility may not be switched more than once every 12 months. A consumer or connecting utility who pays a switchover fee does not waive the right to seek a refund on the basis that the switchover fee was excessive. In addition, a connecting utility or consumer who buys facilities pursuant to this section waives the right to seek a refund only if it expressly agrees to waive that right.

(b) **Definitions.** As used in this section, the following terms have the following meanings.

(1) **Idle facilities** - The disconnecting utility's facilities that are used to serve only the consuming facility being switched, as well as the easements for these facilities. For consuming facilities served above 480 volts, idle facilities also include costs, or a portion of costs, pertaining to the upgrade of transmission and distribution facilities that were necessary to serve the consuming facility, if the current or prior owner of the consuming facility agreed to pay the costs upon switching. In all other respects, idle facilities do not include facilities that were installed or are being used to serve more than one consuming facility, including: facilities that were designed with a capacity greater than necessary to serve the consuming facility being switched in order that additional consuming facilities could be served using the facilities in the future; and upgrades that were made to common facilities in order to serve the consuming facility being switched.

(2) **Common facilities** - The disconnecting utility's facilities that are used, installed, or designed to serve more than one consuming facility, except as specified in the definition of idle facilities.

(c) **Documentation.** The requests, notices, offers, agreements, and switchover requests provided for in this section must be in writing, unless otherwise indicated.

(d) **Notice of switchover options.** Upon receiving an oral switchover request, the disconnecting utility shall at that time orally describe the two switchover options, including stating that there is no charge for a partial switchover, stating that there will be a switchover fee for a full switchover, stating that switchover requests must be in writing, stating that written general information on switchover fees will be provided within two working days, and providing a fax number and mailing address to send the switchover request. Within two working days of a switchover request that does not specify whether a partial or full switchover is being requested, the disconnecting utility shall provide the consumer a document describing the two switchover options, including a statement that there is no charge for a partial switchover, specifying for a full switchover the base charge and base charge adder and stating that the facilities recovery charge will vary depending on the circumstances, and providing the deadlines prescribed in subsection (f)(2)(C) of this subsection for the disconnecting utility to notify the connecting utility after payment of the switchover fee that the full switchover can proceed.

(e) **Partial switchover.**

(1) **Description.** Under the partial switchover option, the connecting utility provides power to the consuming facility using the disconnecting utility's transmission and/or distribution facilities. The disconnecting utility shall provide the connecting utility transmission service to the same point of delivery that the disconnecting utility provided electricity to the consuming facility prior to the switchover. Except where necessary or where the connecting utility requests it, all of the disconnecting utility's facilities needed to serve the consuming facility prior to the switchover shall remain in place. The disconnecting utility may not charge a switchover fee for a partial switchover, except that it may charge the connecting utility a cost-based fee where the connecting utility requests that the disconnecting utility remove facilities that were needed by the disconnecting utility to serve the consuming facility prior to the switchover. In addition, the disconnecting utility may charge a switching customer any account closing fee that applies to all departing customers, not just switching customers.

(2) **Procedure for partial switchover.** The disconnecting utility shall contact the connecting utility within three working days of receiving a request for a partial switchover in order to coordinate the switchover. The switchover shall occur within eight working days of the disconnecting utility's receipt of the request, unless the consumer agrees to a longer schedule or unless good cause exists for not completing the switchover within eight working days. If the switchover will not be completed within eight working days, then the disconnecting utility must notify the consumer, with copies to the commission's Office of Customer Protection and to the connecting utility, providing the reasons why the switchover has been delayed and when the switchover will be completed. This notice must be provided as soon as possible, by fax to the commission's Office of Customer Protection, connecting utility, and, if possible, the consumer.

(f) **Full switchover.** A full switchover involves the disconnecting utility disconnecting its facilities and the connecting utility installing and/or purchasing transmission and/or distribution facilities to serve the consuming facility. If the consumer is a tenant, the consumer must obtain the clear and specific agreement of the owner or owner's agent to switch over the consuming facility and must provide it to the disconnecting utility as an attachment to a notarized affidavit stating that the consumer has obtained the owner's or owner's agent's agreement. This subsection does not apply within municipalities exercising original jurisdiction that enacted switchover rules by August 28, 1998 that provide for more expeditious full switchovers than provided by this subsection.

(1) **Switchover fee.** The switchover fee applies regardless of whether the consumer requesting the switchover has ever received service from the disconnecting utility at the consuming facility. The fee consists of a base charge and, where applicable, a base charge adder and facilities recovery charge. The disconnecting utility may not include in the switchover fee a charge for general administrative expenses related to closing the consumer's account. However, the disconnecting utility shall charge a switching customer any account closing fee that applies to all departing customers, not just switching customers. Where the disconnecting utility is allowed to charge for the original cost of facilities, it must deduct contributions in aid of construction that apply to those facilities. Accumulated

depreciation shall be calculated using the depreciation rates that are currently used to book depreciation. Upon the payment of the switchover fee or purchase, or refusal of an offer to purchase, under the circumstances described in subparagraph (B)(i) of this paragraph, any construction charges owed by the consumer, pursuant to a contract entered into after the effective date of this subsection, for idle facilities used to provide service to the consuming facility being switched are extinguished.

(A) Base charge and base charge adder. A base charge applies to the switchover of a consuming facility served at 480 volts or less. The base charge is equal to the cost of removing any meter and drop line used to serve the consuming facility, and shall be specified in the disconnecting utility's tariff. The switchover fee shall not include the original cost less depreciation and gross salvage of the meter and drop line for switchovers for which the base charge applies. A base charge adder that is less than the base charge must also be specified in the tariff to cover the situation where a consumer switches more than one consuming facility on the same premises at the same time. The base charge adder is equal to the cost of removing any meter and drop line used to serve each additional consuming facility.

(B) Facilities recovery charge. The purpose of the facilities recovery charge is to recover costs related to idle facilities, other than meter and drop line costs covered by a base charge or base charge adder.

(i) Availability of facilities recovery charge. The disconnecting utility may not impose a facilities recovery charge for idle facilities if the connecting utility or consumer purchases the idle facilities at a price equal to net book value and signs an agreement indemnifying the disconnecting utility from liability for the facilities after the purchase of the facilities. Before a consumer can purchase the facilities, it must prove that it has the financial resources to protect the disconnecting utility from liability risks resulting from the sale. Where more than one consumer requests a switchover, the disconnecting utility may not impose a facilities recovery charge for idle facilities if the connecting utility purchases the idle facilities and the common facilities used to serve the consuming facilities being switched, but not used to serve any consuming facilities not being switched, at a price equal to replacement cost less depreciation and signs an indemnity agreement. Replacement cost is equal to: the average original cost of like facilities installed in the most recent full calendar year for which information is available, that would be necessary to serve the consuming facilities being switched if facilities were first installed to serve the consuming facilities at the time of the switchover requests; plus the cost of easements for the facilities if the easements were obtained at the time of the switchover requests. The disconnecting utility also may not impose a facilities recovery charge if it refuses an offer to purchase under the conditions described in this subparagraph.

(ii) Components of facilities recovery charge. The facilities recovery charge consists of the net book value (original cost less depreciation) less net salvage (gross salvage less cost of removal) of the idle facilities. In determining the net book value of the facilities, the original cost of the specific facilities should be used. If the original cost of the specific facilities is not available, the installation date of the facilities shall be determined or estimated and the average original cost of like facilities installed by the disconnecting utility in that year shall be used. If average original cost information is not available for the year in which the idle facilities were installed, then the average original cost of like facilities installed in the most recent full calendar year for which information is available shall be used and shall be deflated to the installation date of the idle facilities. Where average original cost information is used, the average original cost information shall be determined using the information for the operating division in which the consuming facility to be switched is located, if the disconnecting utility maintains original cost information by division.

(C) Labor charges. Labor charges for removing facilities are limited to a reasonable estimate of the direct labor cost (salary, insurance, pension, payroll taxes, etc.) for the time of persons needed to remove the facilities. No allocation of general overhead labor is allowed, but any necessary supervisory or engineering labor specific to the removal of the facilities may be included.

(D) Quantification of charges. The calculation of the base charge, base charge adder, and facilities recovery charge may involve the making of estimates. To the extent that there is a range of reasonable estimates for a particular charge, the estimate at the low end of the range should be used, so that the amount of the switchover fee will be minimized, but still be reasonable and in conformance with this section. Unless the consumer agrees otherwise, there will be no refund or surcharge if the actual cost of performing the switchover is less than or greater than the switchover fee. Instead of a utility-specific base charge and base charge adder, the commission may, through the issuance of an order, establish a single base charge and a single base charge adder to be used by all electric utilities. Likewise, the commission may, through the issuance of an order, establish fixed dollar charges for components of the facilities recovery charge.

(E) Payment of switchover fee and other charges. Before the connecting utility provides service, the disconnecting utility has the right to receive payment of the switchover fee and any other outstanding charges. The connecting utility shall not reimburse the consumer for the switchover fee, and may pay the switchover fee only if the consumer agrees prior to the connecting utility's payment of the fee that the consumer will reimburse the connecting utility for the fee. The agreement must contain a plan for the payment of the fee within a reasonable period of time.

(2) **Procedure for full switchover.**

(A) Notice of switchover fee and procedure. Upon receiving a request for a full switchover, the disconnecting utility must provide the consumer a document that quantifies the switchover fee within 15 working days. This document must be in 12 point, non-bold type and must itemize the base charge, base charge adder, and the facilities recovery charge of the switchover fee. In addition, the document must itemize the components of the facilities recovery charge, including a description of the idle facilities, the installation dates of the idle facilities, the original cost of the idle facilities, the accumulated depreciation associated with the idle facilities, the depreciation rates used to calculate the accumulated depreciation, transportation charges for removing the idle facilities, labor rates, labor hours for removing the idle facilities, and the gross salvage value of the idle facilities. The document must also state immediately below these itemizations, in bold, and in not less than 12 point type: "(Disconnecting utility) may not impose a facilities recovery charge under the circumstances described in Public Utility Commission of Texas Substantive Rule §25.27(f)(1)(B)(i). On request, you will be provided a copy of Rule §25.27."

(B) Sale of both common and idle facilities. If a group of consumers request switchovers, the switchovers may necessitate that the connecting utility acquire common and idle facilities in that case. Within 15 working days of receipt of a request from the connecting utility, the disconnecting utility must provide by fax and mail a detailed, reasonable estimate of replacement cost less depreciation for the idle facilities and the common facilities used to serve the consuming facilities to be switched, but not used to serve any consuming facilities not being switched.

(C) Offer to purchase facilities. Within five working days of receipt of an offer to purchase idle and/or common facilities under the conditions described in paragraph (1)(B)(i) of this subsection, the disconnecting utility must notify the connecting utility by fax, with copies by mail or fax to the consumers, whether it accepts or rejects the offer. If the disconnecting utility rejects the offer, it must also provide revised switchover fees that delete the facilities recovery charges, at the same time that it provides notice of rejection of the offer.

(D) Payment of switchover fee and outstanding balances. Until the switchover fee and all outstanding balances are paid to the disconnecting utility, neither the disconnecting utility nor the connecting utility is under any obligation to take steps to make the switchover, and the connecting utility must not provide service to the consuming facility being switched until it receives notice from the disconnecting utility that the switchover can proceed. The disconnecting utility must within the following deadlines from the receipt of payment, notify the connecting utility by fax that the switchover can proceed: two working days for payment by cash, money order, cashier's check, or, if accepted by the disconnecting utility for bill payment, credit card, and five working days for payment by personal check or other forms of payment.

(E) Deadline for full switchover. Once the disconnecting utility notifies the connecting utility that the switchover can proceed and once the connecting utility notifies the disconnecting utility by fax that the consumer has satisfied the conditions for service from the connecting utility, the switchover must be completed within ten working days unless the consumer agrees to a longer schedule, good cause exists for the disconnecting utility not being able to complete the switchover within ten working days, or the connecting utility needs more time to install facilities, so long as the connecting utility complies with the rules concerning responses to requests for service that apply regardless of whether the request relates to a switchover. If the disconnecting utility does not meet the deadline, then the disconnecting utility must notify the consumer, with copies to the commission's Office of Customer Protection and the connecting utility, providing the reasons why the switchover has been delayed and when the switchover will be completed. This notice must be provided as soon as possible, by fax to the commission's Office of Customer Protection, the connecting utility and, if possible, the consumer.

(F) **Consumer's failure to pay.** The consumer may continue to incur charges for retail electric service from the disconnecting utility after the consumer pays the switchover fee and outstanding balances, and may have an unfulfilled contractual obligation that requires future payment of charges to the disconnecting utility. The disconnecting utility has the right to payment of these charges consistent with §23.45 of this title (relating to Billing). If the consumer has not paid the charges within the appropriate time, the disconnecting utility may notify the connecting utility of the consumer's failure to pay and request that the consumer be disconnected, and must at the same time provide a copy of the notice to the consumer, by fax if possible. Upon receipt of such notification and request and upon receipt from the disconnecting utility of an agreement indemnifying the connecting utility from liability for improper cause for disconnection of service, the connecting utility must disconnect the consumer's service in compliance with the procedures in §23.46 of this title (relating to Discontinuance of Service). Immediately upon verification of the consumer's correction of its failure, the disconnecting utility must notify the connecting utility by fax that the consumer's failure has been corrected, and the connecting utility must immediately reconnect service. The connecting utility shall charge a switching customer any disconnection or reconnection fee that applies to all disconnected customers, not just those who have been disconnected pursuant to this subparagraph.

(g) **Complaint concerning a switchover.** A consumer complaint to the commission concerning a switchover shall be handled according to §23.41(c) of this title (relating to Customer Relations), with the following modification. The commission will forward a complaint that it receives to both the disconnecting utility and the connecting utility, and both utilities must provide an initial response within the deadline specified in §23.41(c).

(h) **Compliance tariff provisions.** An electric utility that has the right to serve in an area for which another utility also has the right to provide retail electric service shall include in its tariff a section entitled "Retail Electric Service Switchovers". Immediately below this title, the tariff shall state: "A request to switch service to a consuming facility to another utility that has the right to serve the facility shall be handled pursuant to Public Utility Commission of Texas Substantive Rule §25.27, a copy of which will be provided upon request." Immediately below this statement, the tariff must specify the electric utility's base charge and base charge adder. The electric utility's tariff shall not include any other information addressing retail electric service switchovers.

§25.28. Bill Payment and Adjustments.

(a) **Bill due date.** The bill provided to the customer shall include the payment due date which shall not be less than 16 days after issuance. The issuance date is the postmark date on the envelope or the issuance date on the bill if there is no postmark on the envelope. A payment for electric utility service is delinquent if not received at the electric utility or at the electric utility's authorized payment agency by the close of business on the due date. If the sixteenth day falls on a holiday or weekend, then the due date shall be the next work day after the sixteenth day.

(b) **Penalty on delinquent bills for retail service.** A one-time penalty not to exceed 5.0% may be charged on a delinquent commercial or industrial bill. The 5.0% penalty on delinquent bills may not be applied to any balance to which the penalty has already been applied. An electric utility providing any service to the state of Texas shall not assess a fee, penalty, interest, or other charge to the state for delinquent payment of a bill.

(c) **Overbilling.** If charges are found to be higher than authorized in the utility's tariffs, then the customer's bill shall be corrected.

- (1) The correction shall be made for the entire period of the overbilling.
- (2) If the utility corrects the overbilling within three billing cycles of the error, it need not pay interest on the amount of the correction.
- (3) If the utility does not correct the overcharge within three billing cycles of the error, it shall pay interest on the amount of the overcharge at the rate set by the commission each year.
  - (A) The interest rate shall be based on an average of prime commercial paper rates for the previous 12 months.
  - (B) Interest on overcharges that are not adjusted by the electric utility within three billing cycles of the bill in error shall accrue from the date of payment or from the date of the bill in error.
  - (C) All interest shall be compounded monthly based on the annual rate.
  - (D) Interest shall not apply to leveling plans or estimated billings.

(d) **Underbilling.** If charges are found to be lower than authorized by the utility's tariffs, or if the electric utility failed to bill the customer for service, then the customer's bill may be corrected.

- (1) The electric utility may backbill the customer for the amount that was underbilled. The backbilling shall not collect charges that extend more than six months from the date the error was discovered unless the underbilling is a result of theft of service by the customer.
- (2) The electric utility may disconnect service if the customer fails to pay underbilled charges.
- (3) If the underbilling is $50 or more, the electric utility shall offer the customer a deferred payment plan option for the same length of time as that of the underbilling. A deferred payment plan need not be offered to a customer whose underpayment is due to theft of service.
- (4) The utility shall not charge interest on underbilled amounts unless such amounts are found to be the result of theft of service (meter tampering, bypass, or diversion) by the customer, as defined in §25.126 of this title (relating to Adjustments Due to Non-Compliant Meters and Meter Tampering in Areas Where Customer Choice Has Been Introduced). Interest on underbilled amounts shall be compounded monthly at the annual rate and shall accrue from the day the customer is found to have first stolen (tampered, bypassed or diverted) the service.

(e) **Disputed bills.**

- (1) If there is a dispute between a customer and an electric utility about a bill for service, the electric utility shall investigate and report the results to the customer. If the dispute is not resolved, the electric utility shall inform the customer of the complaint procedures of the commission pursuant to §25.30 of this title (relating to Complaints).

(2) A customer's service shall not be disconnected for nonpayment of the disputed portion of the bill until the dispute is completely resolved by the electric utility.

(3) If the customer files a complaint with the commission, a customer's service shall not be disconnected for nonpayment of the disputed portion of the bill before the commission completes its informal complaint resolution process and informs the customer of its determination.

(4) The customer is obligated to pay any billings not disputed.

(f) **Notice of alternate payment programs or payment assistance.** When a customer contacts an electric utility and indicates inability to pay a bill or a need for assistance with the bill payment, the electric utility shall inform the customer of all alternative payment and payment assistance programs available from the electric utility, such as deferred payment plans, disconnection moratoriums for the ill, payment assistance program for veterans severely burned in combat, or energy assistance programs, as applicable, and of the eligibility requirements and procedure for applying for each.

(g) **Level and average payment plans.** Electric utilities with seasonal usage patterns or seasonal demands are encouraged to offer a level or average payment plan.

(1) The payment plan may use one of the following methods:

(A) A level payment plan allowing residential customers to pay one-twelfth of that customer's estimated annual consumption at the appropriate customer class rates each month, with provisions for annual adjustments as may be determined based on actual electric use.

(B) An average payment plan allowing residential customers to pay one-twelfth of the sum of that customer's current month's consumption plus the previous 11 months consumption (or an estimate, for a new customer) at the appropriate customer class rates each month, plus a portion of any unbilled balance.

(2) If a customer for electric utility service does not fulfill the terms and obligations of a level payment agreement or an average payment plan, the electric utility shall have the right to disconnect service to that customer pursuant to §25.29 of this title (relating to Disconnection of Service).

(3) The electric utility may require a customer deposit from all customers entering into level payment plans or average payment plans pursuant to the requirements §25.24 of this title (relating to Credit Requirements and Deposits). The electric utility shall pay interest on the deposit and may retain the deposit for the duration of the level or average payment plan.

(h) **Payment arrangements.** A payment arrangement is any agreement between the electric utility and a customer that allows a customer to pay the outstanding bill after its due date but before the due date of the next bill. If the utility issued a disconnection notice before the payment arrangement was made, that disconnection should be suspended until after the due date for the payment arrangement. If a customer does not fulfill the terms of the payment arrangements, the electric utility may disconnect service after the later of the due date for the payment arrangement or the disconnection date indicated in the disconnection notice, pursuant to §25.29 of this title without issuing an additional disconnection notice.

(i) **Deferred payment plan**s. A deferred payment plan is any written arrangement between the electric utility and a customer that allows a customer to pay an outstanding bill in installments that extend beyond the due date of the next bill. A deferred payment plan may be established in person or by telephone, and all deferred payment plans shall be put in writing.

(1) The electric utility shall offer a deferred payment plan to any residential customer, including a guarantor of any residential customer, who has expressed an inability to pay all of the bill, if that customer has not been issued more than two disconnection notices during the preceding 12 months.

(2) Every deferred payment plan shall provide that the delinquent amount may be paid in equal installments lasting at least three billing cycles.

(3) When a customer has received service from its current electric utility for less than three months, the electric utility is not required to offer a deferred payment plan if the customer lacks:
   (A) sufficient credit; or
   (B) a satisfactory history of payment for service from a previous utility.
(4) Every deferred payment plan offered by an electric utility:
   (A) shall state, immediately preceding the space provided for the customer's signature and in boldface type no smaller than 14 point size, the following: **"If you are not satisfied with this contract, or if agreement was made by telephone and you feel this contract does not reflect your understanding of that agreement, contact the electric utility immediately and do not sign this contract. If you do not contact the electric utility, or if you sign this agreement, you may give up your right to dispute the amount due under the agreement except for the electric utility's failure or refusal to comply with the terms of this agreement."** In addition, where the customer and the electric utility representative or agent meet in person, the electric utility representative shall read the preceding statement to the customer. The electric utility shall provide information to the customer in English and Spanish as necessary to make the preceding boldface language understandable to the customer;
   (B) may include a 5.0% penalty for late payment but shall not include a finance charge;
   (C) shall state the length of time covered by the plan;
   (D) shall state the total amount to be paid under the plan;
   (E) shall state the specific amount of each installment;
   (F) shall allow the electric utility to disconnect service if the customer does not fulfill the terms of the deferred payment plan, and shall state the terms for disconnection;
   (G) shall not refuse a customer participation in such a program on the basis of race, color, sex, nationality, religion, or marital status;
   (H) shall be signed by the customer and a copy of the signed plan must be provided to the customer. If the agreement is made over the telephone, then the electric utility shall send a copy of the plan to the customer for signature; and
   (I) shall allow either the customer or the electric utility to initiate a renegotiation of the deferred payment plan if the customer's economic or financial circumstances change substantially during the time of the deferred payment plan.
(5) An electric utility may disconnect a customer who does not meet the terms of a deferred payment plan. However, the electric utility may not disconnect service until a disconnection notice has been issued to the customer indicating that the customer has not met the terms of the plan. The notice and disconnection shall conform with the disconnection rules in §25.29 of this title. The electric utility may renegotiate the deferred payment plan agreement prior to disconnection. If the customer did not sign the deferred payment plan, and is not otherwise fulfilling the terms of the plan, and the customer was previously provided a disconnection notice for the outstanding amount, no additional disconnection notice shall be required.

(j) **Recovery of costs associated with burned veteran payment assistance program.**
(1) An electric utility shall be allowed to recover a cost or expense of the bill payment assistance program established for military veterans when a medical doctor has certified that the veteran has significantly decreased ability to regulate the body temperature because of severe burns received in combat.
(2) The electric utility is entitled to:
   (A) Fully recover all costs and expenses related to the bill payment assistance program;
   (B) Defer each cost or expense related to the bill payment assistance program not explicitly included in base rates; and

(C) Apply carrying charges at the utility's weighted average cost of capital to the extent related to the bill payment assistance program. Carrying charges shall be calculated by multiplying the balance of deferred costs and expenses of the bill payment assistance program by the utility’s weighted-average cost of capital (WACC) as established for the utility in a final commission order in a base rate case, provided that the order was filed within three years prior to the initiation of the bill payment assistance program. Otherwise, a proxy WACC shall be used, with a cost of equity of 10%; and the capital structure and cost of debt as reported in the utility’s most recent Earnings Monitoring Report filed pursuant to §25.73 of this title (relating to Financial and Operating Reports), adjusted for known and measurable changes.

§25.29. Disconnection of Service.

(a) **Disconnection policy.** If an electric utility chooses to disconnect a customer, it must follow the procedures below, or modify them in ways that are more generous to the customer in terms of the cause for disconnection, the timing of the disconnection notice, and the period between notice and disconnection. Each electric utility is encouraged to develop specific policies for disconnection that treat its customers with dignity and respect its customers' or members' circumstances and payment history, and to implement those policies in ways that are consistent and non-discriminatory. Disconnection is an option allowed by the commission, not a requirement placed upon the utility by the commission.

(b) **Disconnection with notice.** Electric utility service may be disconnected after proper notice for any of these reasons:

(1) failure to pay a bill for electric utility service or make deferred payment arrangements by the date of disconnection;

(2) failure to comply with the terms of a deferred payment agreement;

(3) violation of the electric utility's rules on using service in a manner which interferes with the service of others or the operation of nonstandard equipment, if a reasonable attempt has been made to notify the customer and the customer is provided with a reasonable opportunity to remedy the situation;

(4) failure to pay a deposit as required by §25.24 of this title (relating to Credit Requirements and Deposits); or

(5) failure of the guarantor to pay the amount guaranteed, when the electric utility has a written agreement, signed by the guarantor, that allows for disconnection of the guarantor's service.

(c) **Disconnection without prior notice.** Electric utility service may be disconnected without prior notice for any of the following reasons:

(1) where a known dangerous condition exists for as long as the condition exists. Where reasonable, given the nature of the hazardous condition, the electric utility shall post a notice of disconnection and the reason for the disconnection at the place of common entry or upon the front door of each affected residential unit as soon as possible after service has been disconnected;

(2) where service is connected without authority by a person who has not made application for service;

(3) where service was reconnected without authority after termination for nonpayment; or

(4) where there has been tampering with the electric utility company's equipment or evidence of theft of service.

(d) **Disconnection prohibited.** Electric utility service may not be disconnected for any of the following reasons:

(1) delinquency in payment for electric utility service by a previous occupant of the premises;

(2) failure to pay for merchandise, or charges for non-electric utility service, including but not limited to insurance policies or home security systems, provided by the electric utility;

(3) failure to pay for a different type or class of electric utility service unless charges for such service were included on that account's bill at the time service was initiated;

(4) failure to pay charges arising from an underbilling, except theft of service, more than six months prior to the current billing;

(5) failure to pay disputed charges, except for the required average billing payment, until a determination as to the accuracy of the charges has been made by the electric utility or the commission and the customer has been notified of this determination;

(6) failure to pay charges arising from an underbilling due to any faulty metering, unless the meter has been tampered with or unless such underbilling charges are due under §25.126 of this title (relating

to Adjustments Due to Non-Compliant Meters and Meter Tampering in Areas Where Customer Choice Has Been Introduced); or

(7) failure to pay an estimated bill other than a bill rendered pursuant to an approved meter-reading plan, unless the electric utility is unable to read the meter due to circumstances beyond its control.

(e) **Disconnection on holidays or weekends.** Unless a dangerous condition exists or the customer requests disconnection, service shall not be disconnected on holidays or weekends, or the day immediately preceding a holiday or weekend, unless utility personnel are available on those days to take payments and reconnect service.

(f) **Disconnection due to electric utility abandonment.** No electric utility may abandon a customer or a certified service area without written notice to its customers and all similar neighboring utilities, and approval from the commission.

(g) **Disconnection of ill and disabled.** No electric utility may disconnect service at a permanent, individually metered dwelling unit of a delinquent customer when that customer establishes that disconnection of service will cause some person residing at that residence to become seriously ill or more seriously ill.

(1) Each time a customer seeks to avoid disconnection of service under this subsection, the customer must accomplish all of the following by the stated date of disconnection:

(A) have the person's attending physician (for purposes of this subsection, the term "physician" shall mean any public health official, including medical doctors, doctors of osteopathy, nurse practitioners, registered nurses, and any other similar public health official) call or contact the electric utility by the stated date of disconnection;

(B) have the person's attending physician submit a written statement to the electric utility; and

(C) enter into a deferred payment plan.

(2) The prohibition against service termination provided by this subsection shall last 63 days from the issuance of the electric utility bill or a shorter period agreed upon by the electric utility and the customer or physician.

(h) **Disconnection of energy assistance clients.** No electric utility may terminate service to a delinquent residential customer for a billing period in which the electric utility receives a pledge, letter of intent, purchase order, or other notification that the energy assistance provider is forwarding sufficient payment to continue service.

(i) **Disconnection during extreme weather.** An electric utility cannot disconnect a customer anywhere in its service territory on a day when:

(1) the previous day's highest temperature did not exceed 32 degrees Fahrenheit, and the temperature is predicted to remain at or below that level for the next 24 hours, according to the nearest National Weather Service (NWS) reports; or

(2) the NWS issues a heat advisory for any county in the electric utility's service territory, or when such advisory has been issued on any one of the preceding two calendar days.

(j) **Disconnection of master-metered apartments.** When a bill for electric utility services is delinquent for a master-metered apartment complex:

(1) The electric utility shall send a notice to the customer as required in subsection (k) of this section. At the time such notice is issued, the electric utility shall also inform the customer that notice of possible disconnection will be provided to the tenants of the apartment complex in six days if payment is not made before that time.

(2) At least six days after providing notice to the customer and at least four days before disconnecting, the electric utility shall post a minimum of five notices in conspicuous areas in the corridors or

other public places of the apartment complex. Language in the notice shall be in large type and shall read: "Notice to residents of (name and address of apartment complex): Electric utility service to this apartment complex is scheduled for disconnection on (date), because (reason for disconnection)."

(k) **Disconnection notices.** Any disconnection notice issued by an electric utility to a customer must:

(1) not be issued before the first day after the bill is due, to enable the utility to determine whether the payment was received by the due date. Payment of the delinquent bill at the electric utility's authorized payment agency is considered payment to the electric utility.

(2) be a separate mailing or hand delivered with a stated date of disconnection with the words "disconnection notice" or similar language prominently displayed.

(3) have a disconnection date that is not a holiday or weekend day, not less than ten days after the notice is issued.

(4) be in English and in Spanish.

(5) include a statement notifying the customer that if they need assistance paying their bill by the due date, or are ill and unable to pay their bill, they may be able to make some alternate payment arrangement, establish deferred payment plan, or possibly secure payment assistance. The notice shall also advise the customer to contact the electric utility for more information.

(l) **Electric service disconnection of a non-submetered master metered multifamily property**.

(1) In this subsection, "non-submetered master metered multifamily property" means an apartment, a leased or owner-occupied condominium, or one or more buildings containing at least 10 dwellings that receive electric utility service that is master metered but not submetered.

(2) An electric utility in an area where customer choice has not been introduced shall send a written notice of service disconnection to a municipality before disconnecting service to a non-submetered master metered multifamily property for nonpayment if:

(A) the property is located in the municipality; and

(B) the municipality establishes an authorized representative to receive the notice as described by paragraph (3) of this subsection.

(3) No later than January 1st of every year, a municipality wishing to receive notice of disconnection of electric service to a non-submetered master metered multifamily property shall provide the commission with the contact information for the municipality's authorized representative referenced by paragraph (2) of this subsection by submitting that person's name, title, direct mailing address, telephone number, and email address in a P.U.C. Project Number to be established annually for that purpose. The email address provided by the municipality may be for a general mailbox accessible by the authorized representative established for the purpose of receiving such notices.

(4) After January 1st, but no later than January 15th of every year, the commission shall post on its public website the contact information received from every municipality pursuant to paragraph (3) of this subsection. The contact information posted by the commission shall remain in effect during the subsequent 12-month period of February 1 through January 31 for the purpose of the written notice of disconnection required by paragraph (2) of this subsection.

(5) The electric utility shall email the written notice required by this subsection to the municipality's authorized representative not later than the 10th day before the date electric service is scheduled for disconnection. Additional notice may be provided by third-party commercial carrier delivery or certified mail.

(6) The customer safeguards provided by this subsection are in addition to safeguards provided by other law or agency rules.

(7) This subsection does not prohibit a municipality or the commission from adopting customer safeguards that exceed the safeguards provided by this chapter.

§25.30. Complaints.

(a) **Complaints to the electric utility.** A customer or applicant may file a complaint in person, by letter, or by telephone with the electric utility. The electric utility shall promptly investigate and advise the complainant of the results within 21 days.

(b) **Supervisory review by the electric utility.** Any electric utility customer or applicant has the right to request a supervisory review if they are not satisfied with the electric utility's response to their complaint.

(1) If the electric utility is unable to provide a supervisory review immediately following the customer's request, then arrangements for the review shall be made for the earliest possible date.

(2) Service shall not be disconnected before completion of the review. If the customer chooses not to participate in a review then the company may disconnect service, providing proper notice has been issued under the disconnect procedures in §25.29 of this title (relating to Disconnection of Service).

(3) The results of the supervisory review must be provided in writing to the customer within ten days of the review, if requested.

(4) Customers who are dissatisfied with the electric utility's supervisory review must be informed of their right to file a complaint with the commission.

(c) **Complaints to the commission.**

(1) If the complainant is dissatisfied with the results of the electric utility's complaint investigation or supervisory review, the electric utility must advise the complainant of the commission's informal complaint resolution process. The electric utility must also provide the customer the following contact information for the commission: Public Utility Commission of Texas, Office of Customer Protection, P.O. Box 13326, Austin, Texas 78711-3326, (512)936-7120 or in Texas (toll-free) 1-888-782-8477, fax (512)936-7003, e-mail address: customer@puc.state.tx.us, internet address: www.puc.state.tx.us, TTY (512)936-7136, and Relay Texas (toll-free) 1-800-735-2989.

(2) The electric utility shall investigate all complaints and advise the commission in writing of the results of the investigation within 21 days after the complaint is forwarded to the electric utility.

(3) The electric utility shall keep a record for two years after determination by the commission of all complaints forwarded to it by the commission. This record shall show the name and address of the complainant, the date, nature and adjustment or disposition of the complaint. Protests regarding commission-approved rates or charges which require no further action by the electric utility need not be recorded.

§25.31. Information to Applicants and Customers.

(a) **Information to applicants.** Each electric utility shall provide this information to applicants when they request new service or transfer existing service to a new location:

(1) the electric utility's lowest-priced alternatives available at the applicant's location, The information shall begin with the lowest-priced alternative and give full consideration to applicable equipment options and installation charges;

(2) the electric utility's alternate rate schedules and options, including time of use rates and renewable energy tariffs if available; and

(3) the customer information packet described in subsection (c) of this section. This is not required for the transfer of existing service.

(b) **Information regarding rate schedules and classifications and electric utility facilities.**

(1) Each utility shall notify customers affected by a change in rates or schedule of classifications.

(2) Each electric utility shall maintain copies of its rate schedules and rules in each office where applications are received.

(3) Each electric utility shall post a notice in a conspicuous place in each office where applications are received, informing the public that copies of the rate schedules and rules relating to the service of the electric utility, as filed with the commission, are available for inspection.

(4) Each electric utility shall maintain a current set of maps showing the physical locations of its facilities that includes an accurate description of all facilities (substations, transmission lines, etc.). These maps shall be kept by the electric utility in a central location and will be available for commission inspection during normal working hours. Each business office or service center shall have available up-to-date maps, plans, or records of its immediate service area, with other information as may be necessary to enable the electric utility to advise applicants, and others entitled to the information, about the facilities serving that locality.

(c) **Customer information packets**.

(1) The information packet shall be entitled "Your Rights as a Customer". Cooperatives may use the title, "Your Rights as a Member".

(2) The information packet, containing the information required by this section, shall be mailed to all customers on at least every other year at no charge to the customer.

(3) The information shall be written in plain, non-technical language.

(4) The information shall be provided in English and Spanish; however, an electric utility is exempt from the Spanish language requirement if 10% or fewer of its customers are exclusively Spanish-speaking. If the utility is exempt from the Spanish language requirement, it shall notify all customers through a statement in both English and Spanish, in the packet, that the information is available in Spanish from the electric utility, both by mail and at the electric utility's offices.

(5) The information packet shall include all of the following:

(A) the customer's right to information concerning rates and services and the customer's right to inspect or obtain at reproduction cost a copy of the applicable tariffs and service rules;

(B) the electric utility's credit requirements and the circumstances under which a deposit or an additional deposit may be required, how a deposit is calculated, the interest paid on deposits, and the time frame and requirement for return of the deposit to the customer;

(C) the time allowed to pay outstanding bills;

(D) grounds for disconnection of service;

(E) the steps that must be taken before an electric utility may disconnect service;

(F) the steps for resolving billing disputes with the electric utility and how disputes affect disconnection of service;

(G) information on alternative payment plans offered by the electric utility, including, but not limited to, deferred payment plans, level billing programs, average payment plans, as well as a statement that a customer has the right to request these alternative payment plans;

(H) the steps necessary to have service reconnected after involuntary disconnection;

(I) the customer's right to file a complaint with the electric utility, the procedures for a supervisory review, and right to file a complaint with the commission, regarding any matter concerning the electric utility's service. The commission's contact information: Public Utility Commission of Texas, Office of Customer Protection, P.O. Box 13326, Austin, Texas 78711-3326, (512) 936-7120 or in Texas (toll-free) 1-888-782-8477, fax (512) 936-7003, e-mail address: customer@puc.state.tx.us, internet address: www.puc.state.tx.us, TTY (512) 936-7136, and Relay Texas (toll-free) 1-800-735-2989, shall accompany this information;

(J) the hours, addresses, and telephone numbers of electric utility offices and any authorized locations where bills may be paid and information may be obtained or a toll-free telephone number that would provide the customer with this information;

(K) a toll-free telephone number or the equivalent (such as WATS or collect calls) where customers may call to report service problems or make billing inquiries;

(L) a statement that electric utility services are provided without discrimination as to a customer's race, color, sex, nationality, religion, or marital status, and a summary of the company's policy regarding the provision of credit history based upon the credit history of a customer's former spouse;

(M) notice of any special services such as readers or notices in Braille, if available, and the telephone number of the text telephone for the deaf at the commission;

(N) how customers with physical disabilities, and those who care for them, can identify themselves to the electric utility so that special action can be taken to inform these persons of their rights.

(O) the customer's right to have his or her meter tested without charge under §25.124 of this title (relating to Meter Testing);

(P) the customer's right to be instructed by the utility how to read his or her meter, if applicable;

(Q) a statement that funded financial assistance may be available for persons in need of assistance with their electric utility payments, and that additional information may be obtained by contacting the local office of the electric utility, Texas Department of Housing and Community Affairs, or the Public Utility Commission of Texas. The main office telephone number (toll-free number, if available) and address for each state agency shall also be provided; and

(R) information that explains how a residential customer can be recognized as a critical load customer, the benefits of being a critical load customer in an emergency situation, and the process for being placed on the critical load list. For the purposes of this section a "critical load residential customer" shall be defined as a residential customer who has a critical need for electric service because a resident on the premises requires electric service to maintain life.

§25.33. Prompt Payment Act.

(a) **Application.** This section applies to billing by an electric utility (utility) to a "governmental entity" as defined in Texas Government Code Chapter 2251, the Prompt Payment Act (PPA). This section controls over other sections of this chapter to the extent that they conflict.

(b) **Time for payment by a governmental entity.** A payment by a governmental entity subject to the PPA shall become overdue as provided in the PPA.

(c) **Disputed bills.** If there is a billing dispute between a governmental entity and a utility about any bill for utility service, the dispute shall be resolved as provided in the PPA.

(d) **Interest on overdue payment.** Interest on an overdue governmental entity payment shall be calculated by the governmental entity pursuant to the terms of the PPA and remitted to the utility with the overdue payment. However, pursuant to §25.28(b) of this title (relating to Bill Payment and Adjustments), a governmental entity that is also a state agency is not subject to a fee, penalty, interest, or other charge for delinquent payment of a bill.

(e) **Notice.** A utility shall provide written notice to all of its non-residential customers of the applicability of the PPA to the utility's service to governmental entities. This notice shall be completed within six months of the effective date of this section for existing non-residential customers and, within three months of the effective date of this section, shall be provided to a new customer at or before the time that the terms of service are provided to the customer. A utility's failure to provide this notice does not give rise to any independent claim under the PPA, nor does this notice initiate or terminate any party's rights or obligations under the PPA.

(1) The failure of a utility to provide written notice in accordance with this subsection may be considered in a PPA billing complaint.

(2) The failure of a governmental entity to inform the utility of its status as a governmental entity may be considered in a PPA billing complaint.

§25.41. Price to Beat.

(a) **Applicability.** This section applies to all affiliated retail electric providers (REPs) and transmission and distribution utilities, except river authorities. This section does not apply to an electric utility subject to Public Utility Regulatory Act (PURA) §39.102(c) until the end of the utility's rate freeze.

(b) **Purpose.** The purpose of this section is to promote the competitiveness of the retail electric market through the establishment of the price to beat that affiliated REPs must offer to retail customers beginning on January 1, 2002 pursuant to PURA §39.202.

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

(1) **Affiliated electric utility** -- The electric utility from which an affiliated REP was unbundled in accordance with PURA §39.051.

(2) **Competitive retailer** -- A REP or a municipally owned utility or distribution cooperative that offers customer choice in the restructured competitive electric power market or any other entity authorized to sell electric power and energy at retail in Texas.

(3) **Headroom** -- The difference between the average price to beat (in cents per kilowatt hour (kWh)) and the sum of the average non-bypassable charges or credits approved by the commission in a proceeding pursuant to PURA §39.201, or PURA Subchapter G (in cents per kWh) and the representative power price (in cents per kWh). Headroom may be a positive or negative number. A separate headroom number shall be calculated for the typical residential customer and the typical small commercial customer. The calculation for the typical residential customer shall assume 1,000 kWh per month in usage. The calculation of the typical small commercial customer shall assume 35 kilowatts (kW) of demand and 15,000 kWh per month in usage.

(4) **Nonaffiliated REP** -- Any competitive retailer conducting business in a transmission and distribution utility's (TDU's) certificated service territory that is not affiliated with that TDU unless the competitive retailer is a successor in interest to a retail electric provider affiliated with that TDU.

(5) **Peak demand** -- The highest 15-minute or 30-minute demand recorded during a 12-month period.

(6) **Price to beat period** -- The price to beat period shall be from January 1, 2002 to January 1, 2007. In a power region outside the Electric Reliability Council of Texas (ERCOT) if customer choice is introduced before the date the commission certifies the power region pursuant to PURA §39.152(a) are met, the price to beat period continues, unless changed by the commission in accordance with PURA Chapter 39, until the later of 60 months after the date customer choice is introduced in the power region or the date the commission certifies the power region as a qualified power region.

(7) **Provider of last resort (POLR)** -- As defined in §25.43 of this title (relating to Provider of Last Resort).

(8) **Representative power price** -- The simple average of the results of:

(A) a request for proposals (RFP) for full-requirements service of 10% of price to beat load for a duration of three years expressed in cents per kWh; and

(B) the price resulting from the capacity auctions of the affiliated power generation company (PGC) required by §25.381 of this title (relating to Capacity Auctions) for baseload capacity entitlements auctioned in the ERCOT zone where the majority of price to beat customers reside, expressed in cents per kWh. The calculation of the price resulting from the capacity auctions shall assume dispatch of 100% of the entitlement and shall use the most recent auction of a 12-month forward strip of entitlements, or the most recent aggregated forward 12 months of entitlements. The affiliated REP, at its option, may conduct an RFP or purchase auction for an amount equivalent to the amount, in MWs, of the affiliated PGC's capacity auction for the September 2001 12-month forward strip baseload entitlements.

(9) **Residential customer** -- Retail customers classified as residential by the applicable transmission and distribution utility tariff or, in the absence of classification under a residential rate class, those retail customers that are primarily end users consuming electricity for personal, family or household purposes and who are not resellers of electricity.

(10) **Small commercial customer** -- A non-residential retail customer having a peak demand of 1,000 kilowatts (kW) or less. For purposes of this section, the term small commercial customer refers to a metered point of delivery. Additionally, any non-residential, non-metered point of delivery with peak demand of less than 1,000 kW shall also be considered a small commercial customer. For purposes of subsection (i) of this section, unmetered guard and security lights are not considered small commercial customers unless such an account has historically been treated as a separate customer for billing purposes.

(11) **Transmission and distribution utility** -- As defined in §25.5 of this title (relating to Definitions), except for purposes of this section, this term does not include a river authority.

(d) **Price to beat offer.**

(1) Beginning with the first billing cycle of the price to beat period and continuing through the last billing cycle of the price to beat period, an affiliated REP shall make available to residential and small commercial customers of its affiliated transmission and distribution utility rates that, subject to the exception listed in subsection (f)(2)(A) of this section, on a bundled basis, are 6.0% less than the affiliated electric utility's corresponding average residential and small commercial rates that were in effect on January 1, 1999, adjusted to reflect the fuel factor determined in accordance with subsection (f)(3)(D) of this section and adjusted for any base rate reduction as stipulated to by an electric utility in a proceeding for which a final order had not been issued by January 1, 1999.

(2) Unless specifically required by commission rule, an affiliated REP may only sell electricity to price to beat customers labeled or marketed as "green," "renewable," "interruptible," "experimental," "time of use," "curtailable," or "real time," if and only if such a tariff option existed on January 1, 1999 and only for service under the price to beat rate that was developed from that tariff.

(e) **Eligibility for the price to beat.** The following criteria shall be used in determining eligibility for the price to beat:

(1) **Residential customers.** All current and future residential customers, as defined by this section, shall be eligible for the price to beat rate(s) for which they meet the eligibility criteria in the applicable price to beat tariffs for the duration of the price to beat period. An affiliated REP may not refuse service under the price to beat to a residential customer except as provided by §25.477 of this title (relating to Refusal of Service). An affiliated REP may not require residential customers to enter into service agreements with a term of service as a condition of obtaining service under the price to beat, nor may an affiliated REP provide any inducements to encourage customers to agree to a term of service in conjunction with service under the price to beat.

(2) **Small commercial customers.**

(A) A non-residential customer taking service from the affiliated electric utility on December 31, 2001, shall be considered a small commercial customer under this section and shall be eligible for service under price to beat tariffs if that customer's peak demand during the 12 consecutive months ending on September 30, 2001, does not exceed 1,000 kilowatts (kW). A non-residential customer with a peak demand in excess of 1,000 kW during the 12 months ending September 30, 2001, or during the price to beat period, shall no longer be considered a small commercial customer under this section. However, any non-residential customer whose peak demand does not exceed 1,000 kW for any period of 12 consecutive months after it became ineligible to be a small commercial customer under this section shall be considered a small commercial customer for billing periods going forward for purposes of this section.

(B) All small commercial customers, as defined by this section, shall be eligible for the price to beat rate(s) for which they meet the eligibility criteria in the applicable price to beat tariffs for the duration of the price to beat period. An affiliated REP may not refuse service under the price to beat to a small commercial customer, except as provided by §25.477 of this title. An affiliated REP may not require small commercial customers to enter into service agreements with a term of service as a condition to obtaining service under the price to beat, nor may an affiliated REP provide any inducements to encourage customers to agree to a term of service in conjunction with service under the price to beat.

(f) **Calculation of the price to beat.**

(1) **Rates to be used for price to beat calculation.** The following criteria shall be used in determining the rates to be used for the price to beat calculation.

(A) Residential. A price to beat rate shall be calculated for each rate and service rider under which a residential customer was taking service on January 1, 1999, except as approved by the commission pursuant to subparagraph (C) of this paragraph. A price to beat rate shall not be calculated for any new service or tariff option granted to an affiliated electric utility pursuant to PURA §39.054, or any other rate or tariff option not in effect on January 1, 1999.

(i) Beginning with the first full billing cycle of the price to beat period, residential customers served by the affiliated REP shall be placed on the price to beat rate derived from the rate under which they were taking service on December 31, 2001.

(ii) Beginning with the first full billing cycle of the price to beat period, residential customers served by the affiliated REP who were taking service under a rate for which a price to beat rate was not developed, shall be placed on the price to beat rate derived from any eligible residential rate that was or would have been available to the customer on January 1, 1999.

(iii) New residential customers after December 31, 2001, may choose any price to beat rate for which they meet the eligibility requirements as detailed in the applicable price to beat tariff.

(iv) Residential customers who return to the affiliated REP after being served by a non-affiliated REP may choose any price to beat for which they meet the eligibility requirements as detailed in the applicable price to beat tariff(s).

(v) Notwithstanding clauses (i)-(iv) of this subparagraph, residential customers may request service under any price to beat rate for which they are eligible. Selection of the most advantageous rate shall be the sole responsibility of the residential customer.

(B) Small commercial. A price to beat rate shall be calculated for each rate and service rider under which a small commercial customer was taking service on January 1, 1999, except as approved by the commission pursuant to subparagraph (C) of this paragraph. A price to beat rate shall not be calculated for any new service or tariff option granted to an affiliated electric utility pursuant to PURA §39.054, or for any rate of tariff option not in effect on January 1, 1999.

(i) Beginning with the first full billing cycle of the price to beat period, small commercial customers served by the affiliated REP shall be placed on the price to beat rate derived from the rate under which they were taking service on December 31, 2001.

(ii) Beginning with the first full billing cycle of the price to beat period, small commercial customers served by the affiliated REP beginning in January of 2002, who were taking service under a rate for which a price to beat rate was not developed, shall be placed on a price to beat rate derived from an eligible rate that was or would have been available to the customer on January 1, 1999.

(iii) New small commercial customers after December 31, 2001, may choose any price to beat rate for which they meet the eligibility requirements as detailed in the applicable price to beat tariff.

(iv) Small commercial customers who return to the affiliated REP after being served by a non-affiliated REP may choose any price to beat rate for which they meet the eligibility requirements as detailed in the price to beat tariff(s).

(v) Notwithstanding clauses (i)-(iv) of this subparagraph, small commercial customers may request service under any price to beat tariff for which they are eligible. Selection of the most advantageous rate shall be the sole responsibility of the small commercial customer.

(C) An electric utility, on behalf of its future affiliated REP, shall file within 60 days of the effective date of this section, price to beat tariffs and supporting workpapers for the price to beat rates developed in accordance with subparagraphs (A) and (B) of this paragraph. At the time of this filing, the affiliated REP may request that a price to beat rate not be developed from a particular rate of service rider along with justification for the request. The electric utility shall provide notice to all customers currently taking service under such rates or service riders of the utility's request.

(2) **Base rate component of price to beat.** For the eligible rates identified in paragraph (1) of this subsection, the affiliated REP shall reduce each base rate component including any purchased power cost recovery factor (PCRF), in effect for the affiliated electric utility on January 1, 1999, by 6.0% in order to determine the base rate component of the price to beat, with the following exceptions:

(A) If base rates for the affiliated electric utility were reduced by more than 12% as the result of a final order issued by the commission after October 1, 1998, then the price to beat shall be the rate in effect as a result of a settlement approved by the commission after January 1, 1999.

(B) For affiliated REPs operating in a region defined by PURA §39.401, the commission may reduce rates by less than 6.0% if the commission determines a lesser reduction is necessary and consistent with the capital requirements needed to develop the infrastructure necessary to facilitate competition among electric generators.

(C) Except as provided in subparagraphs (A) and (B) of this paragraph, for any affiliated electric utility that has stipulated to rate reductions in a proceeding for which a final order had not been issued by January 1, 1999, such rate reductions shall be deducted from the base rates in effect on January 1, 1999, in addition to the 6.0% reduction. Such rate credits shall also be applied to the rates of the transmission and distribution utility.

(3) **Fuel factor component of price to beat.**

(A) Each affiliated electric utility shall file an application to establish one or more fuel factors, to be effective on January 1, 2002, according to the following schedule:

(i) April 1, 2001 - Reliant Houston Lighting & Power;

(ii) May 1, 2001 - TXU Electric Company;

(iii) June 1, 2001 - Texas-New Mexico Power Company and Central Power & Light Company;

(iv) July 1, 2001 - Entergy Gulf States, Inc. and West Texas Utilities;

(v) August 1, 2001 - Southwestern Electric Power Company and Southwestern Public Service Company.

(B) The rate year for the filing shall be calendar year 2002. The affiliated electric utility shall follow the requirements of §25.237(a)(1), (b), (c) and (e) of this title (relating to Fuel Factors) and the Fuel Factor Filing Package of November 23, 1993, for the filing of its fuel factor(s). To the extent that the commission has issued an order for a utility that includes provisions relating to the price to beat fuel factor, the price to beat fuel factor shall be set consistent with such an order.

(C) Subject to the limitations in clause (i) and (ii) of this subparagraph, affiliated electric utilities may utilize seasonal fuel factors to reflect the expected differences in the cost of the market price of electricity throughout the year.

(i) Affiliated electric utilities with seasonal fuel factors in effect on or before March 1, 2001, may request seasonal fuel factors for their residential and small commercial price to beat customers provided the level of seasonality is identical to that reflected in its commission-approved fuel factors on March 1, 2001.

(ii) Affiliated electric utilities without seasonal fuel factors in effect on or before March 1, 2001, may request seasonal fuel factors to be applicable to small commercial price to beat customers only. Any request for seasonal fuel factors under this clause must demonstrate that the average small commercial customer will receive, on an annual basis, a 6.0% reduction from the average bundled rate in effect on January 1, 1999, adjusted for the final fuel factor determined under subparagraph (D) of this paragraph; provided, however, that a utility subject to the exception in paragraph (2)(A) of this subsection must demonstrate that the average small commercial customer will receive, on an annual basis, the average bundled rate in effect as the result of a settlement approved by the commission after January 1, 1999, adjusted for the final fuel factor determined under subparagraph (D) of this paragraph.

(D) Each affiliated electric utility shall file additional information on October 1, 2001, to reflect changes in the price of natural gas for the rate year of 2002. The affiliated electric utility shall also file information necessary to determine the initial headroom that exists under the price to beat as a result of the setting of the initial price to beat fuel factor pursuant to this subparagraph. The adjustment shall be calculated using the following methodology:

(i) For the ten-day period ending on September 15, 2001, an average price shall be calculated for each month of 2002 in the closing forward NYMEX Henry Hub natural gas prices, as reported in the Wall Street Journal.

(ii) All other inputs into the calculation of the fuel factors will be the same as those used to calculate the fuel factor in subparagraphs (B) and (C) of this paragraph.

(iii) Except for affiliated electric utilities whose base rates were reduced by more than 12% as the result of a final order issued by the commission after October 1, 1998, the fuel factor(s) to be used at the beginning of the price to beat period shall be the fuel factor in effect on January 1, 1999, reduced by 6.0%, plus the difference between the fuel factor(s) established pursuant to this subparagraph and the fuel factor in effect on January 1, 1999.

(iv) The fuel factor(s) for affiliate electric utilities whose base rates were reduced by more than 12% as the result of a final order issued by the commission after October 1, 1998, to be used at the beginning of the price to beat period shall be the fuel factor(s) established pursuant to this subparagraph.

(E) For a non-generating investor-owned utility with no fuel factor as of January 1, 1999, its PCRF in effect on January 1, 1999, shall be the equivalent to a fuel factor for purposes of calculating its price to beat rates and future fuel cost adjustments under subsection (g) of this section. Upon expiration of a purchased power contract of an affiliated REP unbundled from such a utility, the affiliated REP may request a change in its PCRF to account for any difference in purchased power costs.

(g) **Adjustments to the price to beat.**

(1) **Fuel factor adjustments.** An affiliated REP may request that the commission adjust the fuel factor(s) established under subsection (f)(3) of this section upward or downward not more than twice in a calendar year if the affiliated REP demonstrates that the existing fuel factor(s) do not adequately reflect significant changes in the market price of natural gas and purchased energy used to serve retail customers. As part of a filing made pursuant to this paragraph, an affiliated REP may also request an adjustment to the seasonality imparted to the fuel factor in accordance with subsection (f)(3)(C) of this section. Alternatively, the commission may, as part of its approval of an adjustment to the fuel factor, impose a change in the seasonality imparted to the fuel factor. The methodology for calculating the adjustment to the fuel factor(s) shall be the following:

(A) For each day of the 20 trading-day period ending no later than two days before the filing of a fuel factor adjustment application, an average of the closing forward 12-month NYMEX Henry Hub natural gas prices, as reported by the *Wall Street Journal* (either in print or on-line), is calculated.

(B) The average forward price for each trading day calculated in subparagraph (A) of this paragraph will then be averaged to determine a 20 trading-day rolling price.

(C) The percentage difference between the averaged 20 trading-day rolling price calculated under subparagraphs (A) and (B) of this paragraph and the averaged price used to calculate the current fuel factor(s) is calculated. If the current fuel factor was calculated through an adjustment under subparagraph (E) of this paragraph, then the averaged 20 trading-day rolling price calculated concurrent with that adjustment shall be used. If the percentage difference is 5.0% or more, then the current fuel factor(s) may be adjusted, unless the filing is made after November 15 of a calendar year, in which event the percentage difference must be 10% or more.

(D) If the absolute value of the percentage difference calculated in subparagraph (C) of this paragraph meets or exceeds 5.0% (or 10% if applicable), then the current fuel factors are deemed to be unreflective of significant changes in the market price of natural gas and purchased energy. To adjust the current fuel factor(s), the percentage difference calculated in subparagraph (C), either positive or negative, is added to one and then multiplied by the current factor(s). The results are the adjusted fuel factor(s) that will be implemented according to the procedural schedule in clause (i) and (ii) of this subparagraph:

(i) if no hearing is requested within 15 days after the petition has been filed, a final order shall be issued within 20 days, or as soon as practicable thereafter, after the petition is filed;

(ii) if a hearing is requested within 15 days after the petition is filed, a final order shall be issued within 45 days, or as soon as practicable thereafter, after the petition is filed. The 45 day timeline for issuance of an order may be extended upon mutual agreement of the parties. Such agreement may provide for interim rate relief.

(E) In addition to the adjustment permitted under subparagraphs (A)-(D) of this paragraph, an affiliated REP may also request an adjustment to the fuel factor if the headroom under the price to beat decreases as a result of significant changes in the price of purchased energy. In making a request under this subparagraph:

(i) an affiliated REP shall demonstrate that:

(I) the representative power price has changed such that the headroom under the price to beat has decreased; and

(II) the adjustment to the fuel factor is necessary to restore the amount of headroom that existed at the time that the initial price to beat fuel factor was set by the commission using then current forecasts of the representative power price.

(III) an affiliated REP making an adjustment under this subparagraph shall also file the gas price calculation in subparagraphs (A) and (B) of this paragraph for purposes of subsequent adjustments to the fuel factor based on changes in natural gas prices.

(ii) the commission will issue a final order on an application filed under this subparagraph within 60 days, or as soon as practicable thereafter, after the application is filed. The 60 day timeline for issuance of an order may be extended upon mutual agreement of the parties. Such agreement may provide for interim rate relief.

(F) The commission shall, upon a showing made by an interested party, that a sufficiently liquid electricity commodity trading hub (or hubs) or index has developed for the affiliated REP's relevant geographic or power region, allow an affiliated REP to transition to the use of electricity commodity futures prices at that hub or index to adjust the fuel factor to adequately reflect significant changes in the price of purchased energy. After the commission has made a finding that a sufficiently liquid electricity commodity trading hub or index has developed, the affiliated REP shall be required to perform an additional adjustment under subparagraphs (A) through (D) or (E) of this paragraph before utilization of the futures prices at that trading hub or index to change the fuel factor so that a benchmark electricity price can be established. Subsequent changes to the fuel factor shall be based on the percentage change in the electricity commodity index using the same methodology for the natural gas price adjustment under subparagraphs (A) - (D) of this paragraph.

(2) **Adjustment for financial integrity.** Upon a finding that an affiliated REP will be unable to maintain its financial integrity if it complies with subsection (f) of this section, the commission shall set the affiliated REP's price to beat at the minimum level that will allow the affiliated REP to maintain its financial integrity. However, in no event shall the price to beat exceed the level of rates, on a bundled basis, charged by the affiliated electric utility on September 1, 1999, adjusted for fuel.

(3) **True-up adjustment.** The commission shall adjust the price to beat following the true-up proceedings under PURA §39.262. The commission shall consider the following adjustments to the price to beat on a schedule consistent with the processing of the TDU rate adjustment application pursuant to §25.263(n) of this title (relating to True-up Proceeding):

(A) **Fuel factor adjustment.** A 20 trading-day rolling price shall be calculated in accordance with paragraph (1)(A)-(D) of this subsection. If the 20 trading-day rolling price is less than the price used to calculate the then-current fuel factor (i.e. The percentage difference is negative), then the price to beat fuel factor shall be adjusted downward by the percentage difference in the prices. An adjustment required to be made in accordance with this subparagraph shall not be considered a request by an affiliated REP under paragraph (1) of this subsection.

(B) **Base rate adjustment.** Using the typical residential and small commercial usage calculations described in subsection (c)(3) of this section, the base rate components of the price to beat shall be adjusted, either upward or downward, such that the difference between the average price to beat base rate and the average non-bypassable charges that exist following the proceeding pursuant to §25.263(n) of this title is the same as existed on January 1, 2002. Each component of the base rates for each residential price to beat base rate tariff shall be adjusted in the same proportion in complying with this section.

Each component of the base rates for each small commercial price to beat base rate tariff shall be adjusted in the same proportion in complying with this section

(C) **Filing by affiliated REP.** An affiliated REP shall make filings necessary to implement subparagraphs (A) and (B) of this paragraph on a schedule to be determined by the commission.

(h) **Non-price to beat offers.**

(1) **Offers to residential customers.** An affiliated REP may not offer any rates other than the price to beat rates to residential customers within the affiliated electric utility's service area until the earlier of 36 months after the date customer choice is introduced, or when the commission determines that an affiliated REP has met or exceeded the threshold target for residential customers described in subsection (i) of this section.

(2) **Offers to small commercial customers.** An affiliated REP may not offer rates other than the price to beat rates to small commercial customers until the earlier of 36 months after the date customer choice is introduced, or when the commission determines that an affiliated REP has met or exceeded the threshold target for small commercial customers described in subsection (i) of this section.

(3) **Offers to aggregated small commercial load.** Notwithstanding paragraph (2) of this subsection, an affiliated REP may charge rates different from the price to beat for service to aggregated loads having an aggregated peak demand in excess of 1,000 kW provided that all affected customers are commonly owned or are franchisees of the same franchisor.

(A) If aggregated customers whose loads are served by an affiliated REP in accordance with this subsection disaggregate, those individual customers may resume service under the applicable price to beat rate(s), provided that those customers meet the eligibility requirements of subsection (e) of this section.

(B) Any usage removed from the threshold calculation in subsection (i)(1)(B) of this section due to aggregation shall be added back into the threshold calculation upon disaggregation of the aggregated load.

(i) **Threshold targets.**

(1) **Calculation of threshold targets.**

(A) Residential target. The residential threshold target shall be equal to 40% of the total number of kilowatt-hours (kWh) consumed by residential customers served by the affiliated electric utility during the calendar year 2000.

(B) Small commercial target. The small commercial threshold target shall be equal to 40% of the following difference: the total number of kWh consumed by small commercial customers served by the affiliated electric utility during the calendar year 2000 minus the aggregated load served by the affiliated REP that complies with the requirements of subsection (h)(3) of this section. The kWh associated with a customer who becomes ineligible for the price to beat because the customer's peak demand exceeds 1,000 kW shall also be removed from the threshold target.

(2) **Meeting of threshold targets.** Upon a showing by the affiliated transmission and distribution utility that the electric power consumption of the relevant customer group served by nonaffiliated REPs meets or exceeds the targets determined by the calculation in paragraph (1) of this subsection, the affiliated REP may offer rates other than the price to beat.

(A) Calculation of residential consumption. The amount of electric power of residential customers served by nonaffiliated REPs shall equal the number of residential customers served by nonaffiliated REPs, except customers that the affiliated REP has dropped to the POLR, times the average annual consumption of residential customers served by the affiliated utility during the calendar year 2000.

(i) The number of customers served by nonaffiliated REPs shall be determined by summing the number of customers in the transmission and distribution utility's certificated service area with a designated REP other than the affiliated REP in the registration database maintained by the registration agent. Customers dropped to the POLR by the affiliated REP shall not count as load served by a nonaffiliated REP.

(ii) The average annual consumption shall be calculated by dividing the total kWh consumed by residential customers during the calendar year 2000 by the average number of residential customers during the calendar year 2000. The average number of residential customers during the calendar year 2000 shall be calculated by dividing the sum of the total number of such customers for each month of the year 2000 by 12.

(B) Calculation of small commercial consumption. The amount of electric power consumed by small commercial customers served by nonaffiliated REPs shall be determined using the following criteria, except that customers served by the POLR shall not count as load served by a nonaffiliated REP:

(i) The amount of electric power of small commercial customers with peak demand less than 20 kW consumed by nonaffiliated REPs shall be equal to the number of small commercial customers with peak demand less than 20 kW served by nonaffiliated REPs times the average annual consumption of small commercial customers with peak demand less than 20 kW served by the affiliated electric utility during the calendar year 2000.

(I) The number of customers served by nonaffiliated REPs shall be determined by summing the number of small commercial customers with peak demands less than 20 kW served in the transmission and distribution utility's certificated service area with a designated REP other than the affiliated REP in the registration database maintained by the registration agent.

(II) The average annual consumption shall be calculated by dividing the total kWh consumed by small commercial customers with peak demand of less than 20 kW during the calendar year 2000 by the average number of small commercial customers with peak demand of less than 20 kW during the calendar year 2000. The average number of small commercial customers with peak demand of less than 20 kW shall be calculated by dividing the total number of such customers for each month of 2000 by 12.

(ii) The amount of electric power consumed by small commercial customers with peak demand in excess of 20 kW shall be the actual usage of those customers during the calendar year 2000.

(I) If less than 12 months of consumption history exists for such a customer during the calendar year 2000, the available calendar year 2000 usage history shall be supplemented with the most recent prior history of service at that customer's location for the unavailable months.

(II) For customers with service to a new location, the annual consumption shall be deemed to be equal to the estimated maximum annual demand used by the affiliated transmission and distribution utility in sizing the facilities installed to serve that

customer multiplied by the product of 8,760 hours and the average annual load factor for small commercial customers with peak demand greater than 20 kW for the year 2000.

(j) **Prohibition on incentives to switch**. An affiliated REP may not provide an incentive to switch to a nonaffiliated REP, promote any nonaffiliated REP, or exchange customers with any nonaffiliated REP in order to meet the requirements of subsection (f) of this section. Non-affiliated REPs may not provide an incentive to return to the price to beat.

(k) **Disclosure of price to beat rate.** An affiliated retail electric provider shall disclose to customers, the price to beat in accordance with §25.471 (relating to General Provisions of Customer Protection Rules). In addition, if an affiliated REP offers a rate greater than the price to beat, the price to beat rate must be disclosed along with a statement that the customer is eligible for the price to beat. This disclosure must appear on all written authorizations, Internet authorizations, the electricity facts label and Terms of Service document. It must also be disclosed during telephone solicitations before the customer authorizes service.

(l) **Filing requirements.**

(1) On determining that its affiliated retail electric provider has met the requirements of subsection (i) of this section, an electric utility or transmission and distribution utility shall make a filing with the commission attesting under oath to the fact that those requirements have been met and that the restrictions of subsection (h) of this section as well as the true-up in PURA §39.262(e) are no longer applicable.

(2) An electric utility or transmission and distribution utility shall file a progress report with the commission after its affiliated REP has met the requirements of subsection (i) of this section using a 35% threshold target in lieu of a 40% threshold. Such progress reports(s) shall be filed no later than 30 days after the 35% threshold has been met and shall contain the same information required in this subsection.

(3) No later than December 31, 2001, each transmission and distribution utility shall determine the power consumption threshold targets under subsection (i) of this section for residential and small commercial customers within its certificated service area and shall file this information with the commission and shall also make this information publicly available through its Internet website. Each transmission and distribution utility, together with its affiliated REP, shall update the small commercial power consumption threshold as needed to reflect additional small commercial load that has met the requirements of subsection (h)(3) of this section and therefore is appropriately removed from the calculation of the threshold target. Concurrent with this update, the transmission and distribution utility, together with its affiliated REP, shall provide, for each group of aggregated customers that have been removed from the calculation of the threshold target, the customers' names, electric service identifiers, size of the customers' loads (individually and in the aggregate), and how the customers meet the requirements of subsection (h)(3) of this section. Such information may be filed under confidential seal. All certificated REPs shall be deemed to have standing to review such filings.

(4) Any application filed pursuant to this subsection shall contain the following information:

(A) a detailed explanation of how the relevant customer group has met or exceeded the threshold consumption targets in subsection (i) of this section;

(B) calculation of the power consumption threshold target under subsection (i) of this section for the relevant customer group and the date such target was met;

(C) verification of the meeting of the threshold target in the following manner:

(i) for the residential customer class, independent verification from the registration agent verifying the number of customers in the residential customer class within the transmission and distribution utility's certificated service area that are committed to be served by non-affiliated REPs.

(ii) for the small commercial class, an affidavit detailing the number of customers in the small commercial class with peak demand below 20 kW within the transmission and distribution utility's certificated service area committed to be served by non-affiliated REPs and the customers with peak demand in excess of 20 kW with their actual usage calculated in accordance with subsection (i)(2)(B)(ii) of this section within the transmission and distribution utility's certificated service area that are committed to be served by non-affiliated REPs.

(iii) For purposes of this subsection, a residential and small commercial customer has committed to be served by a nonaffiliated retail electric provider if the registration agent has received a switch request for that customer and any mandated cancellation period pursuant to applicable commission rule has expired.

(5) The commission staff shall review all applications filed under this subsection and shall make a recommendation to the commission within ten days after the application is filed to approve or reject the application. If a filing has insufficient information from which the commission can make a determination, the commission may reject the filing without prejudice for refiling the application. The commission shall issue an order approving or rejecting the application within 30 days after the application is filed. An electric utility or transmission and distribution utility filing an application under this subsection shall not charge rates different from the price to beat until the earlier of 36 months after the date customer choice is introduced or the date such application has been approved by the commission.

§25.43. Provider of Last Resort (POLR).

(a) **Purpose.** The purpose of this section is to establish the requirements for Provider of Last Resort (POLR) service and ensure that it is available to any requesting retail customer and any retail customer who is transferred to another retail electric provider (REP) by the Electric Reliability Council of Texas (ERCOT) because the customer's REP failed to provide service to the customer or failed to meet its obligations to the independent organization.

(b) **Application.** The provisions of this section relating to the selection of REPs providing POLR service apply to all REPs that are serving retail customers in transmission and distribution utility (TDU) service areas. This section does not apply when an electric cooperative or a municipally owned utility (MOU) designates a POLR provider for its certificated service area. However, this section is applicable when an electric cooperative delegates its authority to the commission in accordance with subsection (r) of this section to select a POLR provider for the electric cooperative's service area. All filings made with the commission pursuant to this section, including filings subject to a claim of confidentiality, shall be filed with the commission's Filing Clerk in accordance with the commission's Procedural Rules, Chapter 22, Subchapter E, of this title (relating to Pleadings and other Documents).

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

(1) **Affiliate --** As defined in §25.107 of this title (relating to Certification of Retail Electric Providers (REPs).

(2) **Basic firm service** -- Electric service that is not subject to interruption for economic reasons and that does not include value-added options offered in the competitive market. Basic firm service excludes, among other competitively offered options, emergency or back-up service, and stand-by service. For purposes of this definition, the phrase "interruption for economic reasons" does not mean disconnection for non-payment.

(3) **Billing cycle** -- A period bounded by a start date and stop date that REPs and TDUs use to determine when a customer used electric service.

(4) **Billing month** -- Generally a calendar accounting period (approximately 30 days) for recording revenue, which may or may not coincide with the period a customer's consumption is recorded through the customer's meter.

(5) **Business day** -- As defined by the ERCOT Protocols.

(6) **Large non-residential customer** -- A non-residential customer who had a peak demand in the previous 12-month period at or above one megawatt (MW).

(7) **Large service provider** (LSP) -- A REP that is designated to provide POLR service pursuant to subsection (j) of this section.

(8) **Market-based product** -- For purposes of this section, a rate for residential customers that is derived by applying a positive or negative multiplier to the rate described in subsection (m)(2) of this section is not a market-based product.

(9) **Mass transition** -- The transfer of customers as represented by ESI IDs from a REP to one or more POLR providers pursuant to a transaction initiated by the independent organization that carries the mass transition (TS) code or other code designated by the independent organization.

(10) **Medium non-residential customer** -- A non-residential retail customer who had a peak demand in the previous 12-month period of 50 kilowatt (kW) or greater, but less than 1,000 kW.

(11) **POLR area** -- The service area of a TDU in an area where customer choice is in effect.

(12) **POLR provider** -- A volunteer retail electric provider (VREP) or LSP that may be required to provide POLR service pursuant to this section.

(13) **Residential customer** -- A retail customer classified as residential by the applicable TDU tariff or, in the absence of classification under a tariff, a retail customer who purchases electricity for personal, family, or household purposes.

(14) **Transitioned customer** -- A customer as represented by ESI IDs that is served by a POLR provider as a result of a mass transition under this section.

(15) **Small non-residential customer** -- A non-residential retail customer who had a peak demand in the previous 12-month period of less than 50 kW.

(16) **Voluntary retail electric provider** (VREP) -- A REP that has volunteered to provide POLR service pursuant to subsection (i) of this section.

(d) **POLR service.**

(1) There are two types of POLR providers: VREPs and LSPs.

(2) For the purpose of POLR service, there are four classes of customers: residential, small non-residential, medium non-residential, and large non-residential.

(3) A VREP or LSP may be designated to serve any or all of the four customer classes in a POLR area.

(4) A POLR provider shall offer a basic, standard retail service package to customers it is designated to serve, which shall be limited to:

(A) Basic firm service; and

(B)Call center facilities available for customer inquiries.

(5) A POLR provider shall, in accordance with §25.108 of this title (relating to Financial Standards for Retail Electric Providers Regarding the Billing and Collection of Transition Charges), fulfill billing and collection duties for REPs that have defaulted on payments to the servicer of transition bonds or to TDUs.

(6) Each LSP's customer billing for residential customers taking POLR service under a rate prescribed by subsection (m)(2) of this section shall contain notice to the customer that other competitive products or services may be available from the LSP or another REP. The notice shall also include contact information for the LSP, and the Power to Choose website, and shall include a notice from the commission in the form of a bill insert or a bill message with the header "An Important Message from the Public Utility Commission Regarding Your Electric Service" addressing why the customer has been transitioned to an LSP, a description of the purpose and nature of POLR service, and explaining that more information on competitive markets can be found at www.powertochoose.org, or toll-free at 1-866-PWR-4-TEX (1-866-797-4839).

(e) **Standards of service.**

(1) An LSP designated to serve a class in a given POLR area shall serve any eligible customer requesting POLR service or assigned to the LSP pursuant to a mass transition in accordance with the Standard Terms of Service in subsection (f)(1) of this section for the provider customer's class. However, in lieu of providing terms of service to a transitioned customer under subsection (f) of this section and under a rate prescribed by subsection (m)(2) of this section an LSP may at its discretion serve the customer pursuant to a market-based month-to-month product, provided it serves all transitioned customers in the same class and POLR area pursuant to the product.

(2) A POLR provider shall abide by the applicable customer protection rules as provided for under Subchapter R of this chapter (relating to Customer Protection Rules for Retail Electric Service), except that if there is an inconsistency or conflict between this section and Subchapter R of this chapter, the provisions of this section shall apply. However, for the medium non-residential customer class, the customer protection rules as provided for under Subchapter R of this chapter do not apply, except for §25.481 of this title (relating to Unauthorized Charges), §25.485(a)-(b) of this title (relating to Customer Access and Complaint Handling), and §25.495 of this title (relating to Unauthorized Change of Retail Electric Provider).

(3) An LSP that has received commission approval to designate one of its affiliates to provide POLR service on behalf of the LSP pursuant to subsection (k) of this section shall retain responsibility for the provision of POLR service by the LSP affiliate and remains liable for violations of applicable laws and commission rules and all financial obligations of the LSP affiliate associated with the provisioning of POLR service on its behalf by the LSP affiliate.

(f) **Customer information.**

(1) The Standard Terms of Service prescribed in subparagraphs (A)-(D) of this paragraph apply to POLR service provided by an LSP under a rate prescribed by subsection (m)(2) of this section.

(A) Standard Terms of Service, POLR Provider Residential Service:
Figure: 16 TAC §25.43(f)(1)(A)

(B) Standard Terms of Service, POLR Provider Small Non-Residential Service:
Figure: 16 TAC §25.43(f)(1)(B)

(C) Standard Terms of Service, POLR Provider Medium Non-Residential Service:
Figure: 16 TAC §25.43(f)(1)(C)

(D) Standard Terms of Service, POLR Provider Large Non-Residential Service:
Figure: 16 TAC §25.43(f)(1)(D)

(2) An LSP providing service under a rate prescribed by subsection (m)(2) of this section shall provide each new customer the applicable Standard Terms of Service. Such Standard Terms of Service shall be updated as required under §25.475(f) of this title (relating to General Retail Electric Provider Requirements and Information Disclosures to Residential and Small Commercial Customers).

(g) **General description of POLR service provider selection process.**

(1) All REPs shall provide information to the commission in accordance with subsection (h)(1) of this section. Based on this information, the commission's designated representative shall designate REPs that are eligible to serve as POLR providers in areas of the state in which customer choice is in effect, except that the commission shall not designate POLR providers in the service areas of MOUs or electric cooperatives unless an electric cooperative has delegated to the commission its authority to designate the POLR provider, in accordance with subsection (r) of this section.

(2) POLR providers shall serve two-year terms. The initial term for POLR service in areas of the state where retail choice is not in effect as of the effective date of the rule shall be set at the time POLR providers are initially selected in such areas.

(h) **REP eligibility to serve as a POLR provider.** In each even-numbered year, the commission shall determine the eligibility of certified REPs to serve as POLR providers for a term scheduled to commence in January of the next year.

(1) All REPs shall provide information to the commission necessary to establish their eligibility to serve as a POLR provider for the next term. REPs shall file, by July 10th, of each even-numbered year, by service area, information on the classes of customers they provide service to, and for each customer class, the number of ESI IDs the REP serves and the retail sales in megawatt-hours for the annual period ending March 31 of the current year. As part of that filing, a REP may request that the commission designate one of its affiliates to provide POLR service on its behalf pursuant to subsection (k) of this section in the event that the REP is designated as an LSP. The independent organization shall provide to the commission the total number of ESI ID and total MWh data for each class. All REPs shall also provide information on their technical capability and financial ability to provide service to additional customers in a mass transition. The commission's determination regarding eligibility of a REP to serve as POLR provider under the provisions of this section shall not be considered confidential information.

(2) Eligibility to be designated as a POLR provider is specific to each POLR area and customer class. A REP is eligible to be designated a POLR provider for a particular customer class in a POLR area, unless:

(A) A proceeding to revoke or suspend the REP's certificate is pending at the commission, the REP's certificate has been suspended or revoked by the commission, or the REP's certificate is deemed suspended pursuant to §25.107 of this title (relating to Certification of Retail Electric Providers (REPs));

(B) The sum of the numeric portion of the REP's percentage of ESI IDs served and percentage of retail sales by MWhs in the POLR area, for the particular class, is less than 1.0;

(C) The commission does not reasonably expect the REP to be able to meet the criteria set forth in subparagraph (B) of this paragraph during the entirety of the term;

(D) On the date of the commencement of the term, the REP or its predecessor will not have served customers in Texas for at least 18 months;

(E) The REP does not serve the applicable customer class, or does not have an executed delivery service agreement with the service area TDU;

(F) The REP is certificated as an Option 2 REP under §25.107 of this title;

(G) The REP's customers are limited to its own affiliates;

(H) A REP files an affidavit stating that it does not serve small or medium non-residential customers, except for the low-usage sites of the REP's large non-residential customers, or commonly owned or franchised affiliates of the REP's large non-residential customers and opts out of eligibility for either, or both of the small or medium non-residential customer classes; or

(I) The REP does not meet minimum financial, technical and managerial qualifications established by the commission under §25.107 of this title.

(3) For each term, the commission shall publish the names of all of the REPs eligible to serve as a POLR provider under this section for each customer class in each POLR area and shall provide notice to REPs determined to be eligible to serve as a POLR provider. A REP may challenge its eligibility determination within five business days of the notice of eligibility by filing with the commission additional documentation that includes the specific data, the specific calculation, and a specific explanation that clearly illustrate and prove the REP's assertion. Commission staff shall verify the additional documentation and, if accurate, reassess the REP's eligibility. Commission staff shall notify the REP of any change in eligibility status within 10 business days of the receipt of the additional documentation. A REP may then appeal to the commission through a contested case if the REP does not agree with the staff determination of eligibility. The contested status will not delay the designation of POLR providers.

(4) A standard form may be created by the commission for REPs to use in filing information concerning their eligibility to serve as a POLR provider.

(5) If ERCOT or a TDU has reason to believe that a REP is no longer capable of performing POLR responsibilities, ERCOT or the TDU shall make a filing with the commission detailing the basis for its concerns and shall provide a copy of the filing to the REP that is the subject of the filing. If the filing contains confidential information, ERCOT or the TDU shall file the confidential information in accordance with §22.71 of this title (relating to Filing of Pleadings, Documents, and Other Materials). Commission staff shall review the filing, and shall request that the REP demonstrate that it still meets the qualifications to provide the service. The commission staff may initiate a proceeding with the commission to disqualify the REP from providing POLR service. No ESI IDs shall be assigned to a POLR provider after the commission staff initiates a proceeding to disqualify the POLR provider, unless the commission by order confirms the POLR provider's designation.

(i) **VREP list**. Based on the information provided in accordance with this subsection and subsection (h) of this section, the commission shall post the names of VREPs on its webpage, including the aggregate customer count offered by VREPs. A REP may submit a request to be a VREP no earlier than June 1, and no later than July 31, of each even-numbered year. This filing shall include a description of the REP's capabilities to serve additional customers as well as the REP's current financial condition in enough detail to demonstrate that the REP is capable of absorbing a mass transition of customers without technically or financially distressing the REP and the specific information set out in this subsection. The commission's determination regarding eligibility of a REP to serve as a VREP, under the provisions of this section, shall not be considered confidential information.

(1) A VREP shall provide to the commission the name of the REP, the appropriate contact person with current contact information, which customer classes the REP is willing to serve within each POLR area, and the number of ESI IDs the REP is willing to serve by customer class and POLR area in each transition event.

(2) A REP that has met the eligibility requirements of subsection (h) of this section and provided the additional information set out in this subsection is eligible for designation as a VREP.

(3) Commission staff shall make an initial determination of the REPs that are to serve as a VREP for each customer class in each POLR area and publish their names. A REP may challenge its eligibility determination within five business days of the notice of eligibility by submitting to commission staff additional evidence of its capability to serve as a VREP. Commission staff shall reassess the REP's eligibility and notify the REP of any change in eligibility status within 10 business days of the receipt of the additional documentation. A REP may then appeal to the commission through a contested case if the REP does not agree with the staff determination of eligibility. The contested status will not delay the designation of VREPs.

(4) A VREP may file a request at any time to be removed from the VREP list or to modify the number of ESI IDs that it is willing to serve as a VREP. If the request is to increase the number of ESI IDs, it shall provide information to demonstrate that it is capable of serving the additional ESI IDs, and the commission staff shall make an initial determination, which is subject to an appeal to the commission, in accordance with the timelines specified in paragraph (3) of this subsection. If the request is to decrease the number of ESI IDs, the request shall be effective five calendar days after the request is filed with the commission; however, after the request becomes effective the VREP shall continue to serve ESI IDs previously acquired through a mass transition event as well as ESI IDs the VREP acquires from a mass transition event that occurs during the five-day notice period. If in a mass transition a VREP is able to acquire more customers than it originally volunteered to serve, the VREP may work with commission staff and ERCOT to increase its designation. Changes approved by commission staff shall be communicated to ERCOT and shall be implemented for the current allocation if possible.

(5) ERCOT or a TDU may challenge a VREP's eligibility. If ERCOT has reason to believe that a REP is no longer capable of performing VREP responsibilities, ERCOT shall make a filing with the commission detailing the basis for its concerns and shall provide a copy of the filing to the REP that is the subject of the filing. If the filing contains confidential information, ERCOT or the TDU shall file it in accordance with §25.71 of this title (relating to General Procedures, Requirements and Penalties). Commission staff shall review the filing of ERCOT and if commission staff concludes that the REP should no longer provide VREP service, it shall request that the REP demonstrate that it still meets the qualifications to provide the service. The commission staff may initiate a proceeding with the commission to disqualify the REP from providing VREP service. No ESI IDs shall be assigned to a VREP after the commission staff initiates a proceeding to disqualify the VREP, unless the commission by order confirms the VREP's designation.

(j) **LSPs.** This subsection governs the selection and service of REPs as LSPs.

(1) The REPs eligible to serve as LSPs shall be determined based on the information provided by REPs in accordance with subsection (h) of this section. However, for new TDU service areas that are transitioned to competition, the transition to competition plan approved by the commission may govern the selection of LSPs to serve as POLR providers.

(2) In each POLR area, for each customer class, the commission shall designate up to 15 LSPs. The eligible REPs that have the greatest market share based upon retail sales in megawatt-hours, by customer class and POLR area shall be designated as LSPs. Commission staff shall designate the LSPs by October 15th of each even-numbered year, based upon the data submitted to the commission under subsection (h) of this section. Designation as a VREP does not affect a REP's eligibility to also serve as an LSP.

(3) For the purpose of calculating the POLR rate for each customer class in each POLR area, an EFL shall be completed by the LSP that has the greatest market share in accordance with paragraph (2) of this subsection. The Electricity Facts Label (EFL) shall be supplied to commission staff electronically for placement on the commission webpage by January 1 of each year, and more often if there are changes to the non-bypassable charges. Where REP-specific information is required to be inserted in the EFL, the LSP supplying the EFL shall note that such information is REP-specific.

(4) An LSP serving transitioned residential and small non-residential customers under a rate prescribed by subsection (m)(2) of this section shall move such customers to a market-based month-to-month product, with pricing for such product to be effective no later than either the 61st day of service by the LSP or beginning with the customer's next billing cycle date following the 60th day of service by the LSP. For each transition event, all such transitioned customers in the same class and POLR area must be served pursuant to the same product terms, except for those customers specified in subparagraph (B) of this paragraph.

(A) The notice required by §25.475(d) of this title to inform the customers of the change to a market-based month-to-month product may be included with the notice required by subsection (t)(3) of this section or may be provided 14 days in advance of the change. If the §25.475(d) notice is included with the notice required by subsection (t)(3) of this section, the LSP may state that either or both the terms of service document and EFL for the market-based month-to-month product shall be provided at a later time, but no later than 14 days before their effective date.

(B) The LSP is not required to transfer to a market-based product any transitioned customer who is delinquent in payment of any charges for POLR service to such LSP as of the 60th day of service. If such a customer becomes current in payments to the LSP, the LSP shall move the customer to a market-based month-to-month product as described in this paragraph on the next billing cycle that occurs five business days after the customer becomes current. If the LSP does not plan to move customers who are delinquent in payment of any charges for POLR service as of the 60th day of service to a market-based month-to-month product, the LSP shall inform the customer of that potential outcome in the notice provided to comply with §25.475(d) of this title.

(5) Upon a request from an LSP and a showing that the LSP will be unable to maintain its financial integrity if additional customers are transferred to it under this section, the commission may relieve an LSP from a transfer of additional customers. The LSP shall continue providing continuous service until the commission issues an order relieving it of this responsibility. In the event the requesting LSP is relieved of its responsibility, the commission staff designee shall, with 90 days' notice, designate the next eligible REP, if any, as an LSP, based upon the criteria in this subsection.

(k) **Designation of an LSP affiliate to provide POLR service on behalf of an LSP.**

(1) An LSP may request the commission designate an LSP affiliate to provide POLR service on behalf of the LSP either with the LSP's filing under subsection (h) of this section or as a

separate filing in the current term project. The filing shall be made at least 30 days prior to the date when the LSP affiliate is to begin providing POLR service on behalf of the LSP. To be eligible to provide POLR service on behalf of an LSP, the LSP affiliate must be certificated to provide retail electric service; have an executed delivery service agreement with the service area TDU; and meet the requirements of subsection (h)(2) of this section, with the exception of subsection (h)(2)(B), (C), (D), and (E) of this section as related to serving customers in the applicable customer class.

(2) The request shall include the name and certificate number of the LSP affiliate, information demonstrating the affiliation between the LSP and the LSP affiliate, and a certified agreement from an officer of the LSP affiliate stating that the LSP affiliate agrees to provide POLR service on behalf of the LSP. The request shall also include an affidavit from an officer of the LSP stating that the LSP will be responsible and indemnify any affected parties for all financial obligations of the LSP affiliate associated with the provisioning of POLR service on behalf of the LSP in the event that the LSP affiliate defaults or otherwise does not fulfill such financial obligations.

(3) Commission staff shall make an initial determination of the eligibility of the LSP affiliate to provide POLR service on behalf of an LSP and publish their names. The LSP or LSP affiliate may challenge commission staff's eligibility determination within five business days of the notice of eligibility by submitting to commission staff additional evidence of its capability to provide POLR service on behalf of the LSP. Commission staff shall reassess the LSP affiliate's eligibility and notify the LSP and LSP affiliate of any change in eligibility status within 10 business days of the receipt of the additional documentation. If the LSP or LSP affiliate does not agree with staff's determination of eligibility, either or both may then appeal the determination to the commission through a contested case. The LSP shall provide POLR service during the pendency of the contested case.

(4) ERCOT or a TDU may challenge an LSP affiliate's eligibility to provide POLR service on behalf of an LSP. If ERCOT or a TDU has reason to believe that an LSP affiliate is not eligible or is not performing POLR responsibilities on behalf of an LSP, ERCOT or the TDU shall make a filing with the commission detailing the basis for its concerns and shall provide a copy of the filing to the LSP and the LSP affiliate that are the subject of the filing. If the filing contains confidential information, ERCOT or the TDU shall file it in accordance with §25.71 of this title (relating to General Procedures, Requirements and Penalties). Commission staff shall review the filing and if commission staff concludes that the LSP affiliate should not be allowed to provide POLR service on behalf of the LSP, it shall request that the LSP affiliate demonstrate that it has the capability. The commission staff shall review the LSP affiliate's filing and may initiate a proceeding with the commission to disqualify the LSP affiliate from providing POLR service. The LSP affiliate may continue providing POLR service to ESI IDs currently receiving the service during the pendency of the proceeding; however, the LSP shall immediately assume responsibility to provide service under this section to customers who request POLR service, or are transferred to POLR service through a mass transition, during the pendency of the proceeding.

(5) Designation of an affiliate to provide POLR service on behalf of an LSP shall not change the number of ESI IDs served or the retail sales in megawatt-hours for the LSP for the reporting period nor does such designation relieve the LSP of its POLR service obligations in the event that the LSP affiliate fails to provide POLR service in accordance with the commission rules.

(6) The designated LSP affiliate shall provide POLR service and all reports as required by the commission's rules on behalf of the LSP.

(7) The methodology used by a designated LSP affiliate to calculate POLR rates shall be consistent with the methodology used to calculate LSP POLR rates in subsection (m) of this section.

(8) If an LSP affiliate designated to provide POLR service on behalf of an LSP cannot meet or fails to meet the POLR service requirements in applicable laws and Commission rules, the

LSP shall provide POLR service to any ESI IDs currently receiving the service from the LSP affiliate and to ESI IDs in a future mass transition or upon customer request.

(9) An LSP may elect to reassume provisioning of POLR service from the LSP affiliate by filing a reversion notice with the commission and notifying ERCOT at least 30 days in advance.

(l) **Mass transition of customers to POLR providers**. The transfer of customers to POLR providers shall be consistent with this subsection.

(1) ERCOT shall first transfer customers to VREPs, up to the number of ESI IDs that each VREP has offered to serve for each customer class in the POLR area. ERCOT shall use the VREP list to assign ESI IDs to the VREPs in a non-discriminatory manner, before assigning customers to the LSPs. A VREP shall not be assigned more ESI IDs than it has indicated it is willing to serve pursuant to subsection (i) of this section. To ensure non-discriminatory assignment of ESI IDs to the VREPs, ERCOT shall:

(A) Sort ESI IDs by POLR area;

(B) Sort ESI IDs by customer class;

(C) Sort ESI IDs numerically;

(D) Sort VREPs numerically by randomly generated number; and

(E) Assign ESI IDs in numerical order to VREPs, in the order determined in subparagraph (D) of this paragraph, in accordance with the number of ESI IDs each VREP indicated a willingness to serve pursuant to subsection (i) of this section. If the number of ESI IDs is less than the total that the VREPs indicated that they are willing to serve, each VREP shall be assigned a proportionate number of ESI IDs, as calculated by dividing the number that each VREP indicated it was willing to serve by the total that all VREPs indicated they were willing to serve, multiplying the result by the total number of ESI IDs being transferred to the VREPs, and rounding to a whole number.

(2) If the number of ESI IDs exceeds the amount the VREPs are designated to serve, ERCOT shall assign remaining ESI IDs to LSPs in a non-discriminatory fashion, in accordance with their percentage of market share based upon retail sales in megawatt-hours, on a random basis within a class and POLR area, except that a VREP that is also an LSP that volunteers to serve at least 1% of its market share for a class of customers in a POLR area shall be exempt from the LSP allocation up to 1% of the class and POLR area. To ensure non-discriminatory assignment of ESI IDs to the LSPs, ERCOT shall:

(A) Sort the ESI IDs in excess of the allocation to VREPs, by POLR area;

(B) Sort ESI IDs in excess of the allocation to VREPs, by customer class;

(C) Sort ESI IDs in excess of the allocation to VREPs, numerically;

(D) Sort LSPs, except LSPs that volunteered to serve 1% of their market share as a VREP, numerically by MWhs served;

(E) Assign ESI IDs that represent no more than 1% of the total market for that POLR area and customer class less the ESI IDs assigned to VREPs that volunteered to serve at least 1% of their market share for each POLR area and customer class in numerical order to LSPs designated in subparagraph (D) of this paragraph, in proportion to the percentage of MWhs served by each LSP to the total MWhs served by all LSPs;

(F) Sort LSPs, including any LSPs previously excluded under subparagraph (D) of this paragraph; and

(G) Assign all remaining ESI IDs in numerical order to LSPs in proportion to the percentage of MWhs served by each LSP to the total MWhs served by all LSPs.

(3) Each mass transition shall be treated as a separate event.

(m) **Rates applicable to POLR service.**

(1) A VREP shall provide service to customers using a market-based, month-to-month product. The VREP shall use the same market-based, month-to-month product for all customers in a mass transition that are in the same class and POLR area.

(2) Subparagraphs (A)-(C) of this paragraph establish the maximum rate for POLR service charged by an LSP. An LSP may charge a rate less than the maximum rate if it charges the lower rate to all customers in a mass transition that are in the same class and POLR area.

(A) **Residential customers. T**he LSP rate for the residential customer class shall be determined by the following formula:

LSP rate (in $ per kWh) = (Non-bypassable charges + LSP customer charge + LSP energy charge) / kWh used

Where:

(i) Non-bypassable charges shall be all TDU charges and credits for the appropriate customer class in the applicable service territory and other charges including ERCOT administrative charges, nodal fees or surcharges, reliability unit commitment (RUC) capacity short charges attributable to LSP load, and applicable taxes from various taxing or regulatory authorities, multiplied by the level of kWh and kW used, where appropriate.

(ii) LSP customer charge shall be $0.06 per kWh.

(iii) LSP energy charge shall be the sum over the billing period of the actual hourly Real-Time Settlement Point Prices (RTSPPs) for the customer's load zone that is multiplied by the number of kWhs the customer used during that hour and that is further multiplied by 120%.

(iv) "Actual hourly RTSPP" is an hourly rate based on a simple average of the actual interval RTSPPs over the hour.

(v) "Number of kWhs the customer used" is based either on interval data or on an allocation of the customer's total actual usage to the hour based on a ratio of the sum of the ERCOT backcasted profile interval usage data for the customer's profile type and weather zone over the hour to the total of the ERCOT backcasted profile interval usage data for the customer's profile type and weather zone over the customer's entire billing period.

(vi) For each billing period, if the sum over the billing period of the actual hourly RTSPP for a customer multiplied by the number of kWhs the customer used during that hour falls below the simple average of the RTSPPs for the load zone located partially or wholly in the customer's TDU service territory that had the highest simple average price over the 12-month period ending September 1 of the preceding year multiplied by the number of kWhs the customer used during the customer's billing period, then the LSP energy charge shall be the simple average of the RTSPPs for the load zone partially or wholly in the customer's TDU service territory that had the highest simple average over the 12-month period ending September 1 of the preceding year multiplied by the number of kWhs the customer used during the customer's billing period multiplied by 125%. This methodology shall apply until the commission issues an order suspending or modifying the operation of the floor after conducting an investigation.

(B)**Small and medium non-residential customers. T**he LSP rate for the small and medium non-residential customer classes shall be determined by the following formula:

LSP rate (in $ per kWh) = (Non-bypassable charges + LSP customer charge + LSP demand charge + LSP energy charge) / kWh used

Where:

(i) Non-bypassable charges shall be all TDU charges and credits for the appropriate customer class in the applicable service territory, and other charges including ERCOT administrative charges, nodal fees or surcharges, RUC capacity short charges attributable to LSP load, and applicable taxes from various taxing or regulatory authorities, multiplied by the level of kWh and kW used, where appropriate.

(ii) LSP customer charge shall be $0.025 per kWh.

(iii) LSP demand charge shall be $2.00 per kW, per month, for customers that have a demand meter, and $50.00 per month for customers that do not have a demand meter.

(iv) LSP energy charge shall be the sum over the billing period of the actual hourly RTSPPs, for the customer's load zone that is multiplied by number of kWhs the customer used during that hour and that is further multiplied by 125%.

(v) "Actual hourly RTSPP" is an hourly rate based on a simple average of the actual interval RTSPPs over the hour.

(vi) "Number of kWhs the customer used" is based either on interval data or on an allocation of the customer's total actual usage to the hour based on a ratio of the sum of the ERCOT backcasted profile interval usage data for the customer's profile type and weather zone over the hour to the total of the ERCOT backcasted profile interval usage data for the customer's profile type and weather zone over the customer's entire billing period.

(vii) For each billing period, if the sum over the billing period of the actual hourly RTSPP for a customer multiplied by the number of kWhs the customer used during that hour falls below the simple average of the RTSPPs for the load zone located partially or wholly in the customer's TDU service territory that had the highest simple average over the 12-month period ending September 1 of the preceding year multiplied by the number of kWhs the customer used during the customer's billing period, then the LSP energy charge shall be the simple average of the RTSPPs for the load zone located partially or wholly in the customer's TDU service territory that had the highest simple average price over the 12-month period ending September 1 of the preceding year multiplied by the number of kWhs the customer used during the customer's billing period multiplied by 125%. This methodology shall apply until the commission issues an order suspending or modifying the operation of the floor after conducting an investigation.

(C) **Large non-residential customers. T**he LSP rate for the large non-residential customer class shall be determined by the following formula:

LSP rate (in $ per kWh) = (Non-bypassable charges + LSP customer charge + LSP demand charge + LSP energy charge) / kWh used

Where:

(i) Non-bypassable charges shall be all TDU charges and credits for the appropriate customer class in the applicable service territory, and other charges including ERCOT administrative charges, nodal fees or surcharges, RUC capacity short charges attributable to LSP load, and applicable taxes from various taxing or regulatory authorities, multiplied by the level of kWh and KW used, where appropriate.

(ii) LSP customer charge shall be $2,897.00 per month.

(iii) LSP demand charge shall be $6.00 per kW, per month.

(iv) LSP energy charge shall be the appropriate RTSPP, determined on the basis of 15-minute intervals, for the customer multiplied by 125%, multiplied by the level of kilowatt-hours used. The energy charge shall have a floor of $7.25 per MWh.

(3) If in response to a complaint or upon its own investigation, the commission determines that an LSP failed to charge the appropriate rate prescribed by paragraph (2) of this subsection, and as a result overcharged its customers, the LSP shall issue refunds to the specific customers who were overcharged.

(4) On a showing of good cause, the commission may permit the LSP to adjust the rate prescribed by paragraph (2) of this subsection, if necessary to ensure that the rate is sufficient to allow the LSP to recover its costs of providing service. Notwithstanding any other commission rule to the contrary, such rates may be adjusted on an interim basis for good cause shown and after at least 10 business days' notice and an opportunity for hearing on the request for interim relief. Any adjusted rate shall be applicable to all LSPs charging the rate prescribed by paragraph (2) of this subsection to the specific customer class, within the POLR area that is subject to the adjustment.

(5) For transitioned customers, the customer and demand charges associated with the rate prescribed by paragraph (3) of this subsection shall be pro-rated for partial month usage if a large non-residential customer switches from the LSP to a REP of choice.

(n) **Challenges to customer assignments.** A POLR provider is not obligated to serve a customer within a customer class or a POLR area for which the REP is not designated as a POLR provider, after a successful challenge of the customer assignment. A POLR provider shall use the ERCOT market variance resolution tool to challenge a customer class assignment with the TDU. The TDU shall make the final determination based upon historical usage data and not premise type. If the customer class assignment is changed and a different POLR provider for the customer is determined appropriate, the customer shall then be served by the appropriate POLR provider. Back dated transactions may be used to correct the POLR assignment.

(o) **Limitation on liability.** The POLR providers shall make reasonable provisions to provide service under this section to any ESI IDs currently receiving the service and to ESI IDs obtained in a future mass transition or served upon customer request; however, liabilities not excused by reason of force majeure or otherwise shall be limited to direct, actual damages.

(1) Neither the customer nor the POLR provider shall be liable to the other for consequential, incidental, punitive, exemplary, or indirect damages. These limitations apply without regard to the cause of any liability or damage.

(2) In no event shall ERCOT or a POLR provider be liable for damages to any REP, whether under tort, contract or any other theory of legal liability, for transitioning or attempting to transition a customer from such REP to the POLR provider to carry out this section, or for marketing, offering or providing competitive retail electric service to a customer taking service under this section from the POLR provider.

(p) **REP obligations in a transition of customers to POLR service.**

(1) A customer may initiate service with an LSP by requesting such service at the rate prescribed by subsection (m)(2) of this section with any LSP that is designated to serve the requesting customer's customer class within the requesting customer's service area. An LSP cannot refuse a customer's request to make arrangements for POLR service, except as otherwise permitted under this title.

(2) The POLR provider is responsible for obtaining resources and services needed to serve a customer once it has been notified that it is serving that customer. The customer is responsible for charges for service under this section at the rate in effect at that time.

(3) If a REP terminates service to a customer, or transitions a customer to a POLR provider, the REP is financially responsible for the resources and services used to serve the customer until it notifies the independent organization of the termination or transition of the service and the transfer to the POLR provider is complete.

(4) The POLR provider is financially responsible for all costs of providing electricity to customers from the time the transfer or initiation of service is complete until such time as the customer ceases taking service under this section.

(5) A defaulting REP whose customers are subject to a mass transition event shall return the customers' deposits within seven calendar days of the initiation of the transition.

(6) ERCOT shall create a single standard file format and a standard set of customer billing contact data elements that, in the event of a mass transition, shall be used by the exiting REP and the POLRs to send and receive customer billing contact information. The process, as developed by ERCOT shall be tested on a periodic basis. All REPs shall submit timely, accurate, and complete files, as required by ERCOT in a mass transition event, as well as for periodic testing. The commission shall establish a procedure for the verification of customer information submitted by REPs to ERCOT. ERCOT shall notify the commission if any REP fails to comply with the reporting requirements in this subsection.

(7) When customers are to be transitioned or assigned to a POLR provider, the POLR provider may request usage and demand data, and customer contact information including email, telephone number, and address from the appropriate TDU and from ERCOT, once the transition to the POLR provider has been initiated. Customer proprietary information provided to a POLR provider in accordance with this section shall be treated as confidential and shall only be used for mass transition related purposes.

(8) Information from the TDU and ERCOT to the POLR providers shall be provided in Texas SET format when Texas SET transactions are available. However, the TDU or ERCOT may supplement the information to the POLR providers in other formats to expedite the transition. The transfer of information in accordance with this section shall not constitute a violation of the customer protection rules that address confidentiality.

(9) A POLR provider may require a deposit from a customer that has been transitioned to the POLR provider to continue to serve the customer. Despite the lack of a deposit, the POLR provider is obligated to serve the customer transitioned or assigned to it, beginning on the service initiation date of the transition or assignment, and continuing until such time as any disconnection request is effectuated by the TDU. A POLR provider may make the request for deposit before it begins serving the customer, but the POLR provider shall begin providing service to the customer even if the service initiation date is before it receives the deposit - if any deposit is required. A POLR provider shall not disconnect the customer until the appropriate time period to submit the deposit has elapsed. For the large non-residential customer class, a POLR provider may require a deposit to be provided in three calendar days. For the residential customer class, the POLR provider may require a deposit to be provided after 15 calendar days of service if the customer received 10 days' notice that a deposit was required. For all other customer classes, the POLR provider may require a deposit to be provided in 10 calendar days. The POLR provider may waive the deposit requirement at the customer's request if deposits are waived in a non-discriminatory fashion. If the POLR provider obtains sufficient data, it shall determine whether a residential customer has satisfactory credit based on the criteria the POLR provider routinely applies to its other residential customers. If the customer has satisfactory credit, the POLR provider shall not request a deposit from the residential customer.

(A) At the time of a mass transition, the Executive Director or staff designated by the Executive Director shall distribute available proceeds from an irrevocable stand-by letter of credit in accordance with the priorities established in §25.107(f)(6) of this title. For a REP that has obtained a current list from the Low Income List Administrator (LILA) that identifies low-income customers, these funds shall first be used to provide deposit payment assistance for that REP's transitioned low-income customers. The Executive Director or staff designee shall, at the time of a transition event, determine the reasonable deposit amount up to $400 per customer ESI ID, unless good cause exists to increase the level of the reasonable deposit amount above

$400. Such reasonable deposit amount may take into account factors such as typical residential usage and current retail residential prices, and, if fully funded, shall satisfy in full the customers' initial deposit obligation to the VREP or LSP.

(B) For a REP that has obtained a current list from the LILA that identifies low-income customers, the Executive Director or the staff designee shall distribute available proceeds pursuant to §25.107(f)(6) of this title to the VREPs proportionate to the number of customers they received in the mass transition, who at the time of the mass transition were identified as low-income customers by the current LILA list, up to the reasonable deposit amount set by the Executive Director or staff designee. If funds remain available after distribution to the VREPs, the remaining funds shall be distributed to the appropriate LSPs by dividing the amount remaining by the number of low income customers as identified in the LILA list that are allocated to LSPs, up to the reasonable deposit amount set by the Executive Director or staff designee.

(C) If the funds distributed in accordance with §25.107(f)(6) of this title do not equal the reasonable deposit amount determined, the VREP and LSP may request from the customer payment of the difference between the reasonable deposit amount and the amount distributed. Such difference shall be collected in accordance with §25.478(e)(3) of this title (relating to Credit Requirements and Deposits).

(D) Notwithstanding §25.478(d) of this title, 90 days after the transition date, the VREP or LSP may request payment of an amount that results in the total deposit held being equal to what the VREP or LSP would otherwise have charged a customer in the same customer class and service area in accordance with §25.478(e) of this title, at the time of the transition.

(10) On the occurrence of one or more of the following events, ERCOT shall initiate a mass transition to POLR providers, of all of the customers served by a REP:

(A) Termination of the Load Serving Entity (LSE) or Qualified Scheduling Entity (QSE) Agreement for a REP with ERCOT;

(B) Issuance of a commission order recognizing that a REP is in default under the TDU Tariff for Retail Delivery Service;

(C) Issuance of a commission order de-certifying a REP;

(D) Issuance of a commission order requiring a mass transition to POLR providers;

(E) Issuance of a judicial order requiring a mass transition to POLR providers; and

(F) At the request of a REP, for the mass transition of all of that REP's customers.

(11) A REP shall not use the mass transition process in this section as a means to cease providing service to some customers, while retaining other customers. A REP's improper use of the mass transition process may lead to de-certification of the REP.

(12) ERCOT may provide procedures for the mass transition process, consistent with this section.

(13) A mass transition under this section shall not override or supersede a switch request made by a customer to switch an ESI ID to a new REP of choice, if the request was made before a mass transition is initiated. If a switch request has been made but is scheduled for any date after the next available switch date, the switch shall be made on the next available switch date.

(14) Customers who are mass transitioned shall be identified for a period of 60 calendar days. The identification shall terminate at the first completed switch or at the end of the 60-day period, whichever is first. If necessary, ERCOT system changes or new transactions shall be implemented no later than 14 months from the effective date of this section to communicate that a customer was acquired in a mass transition and is not charged the out-of-cycle meter read pursuant to paragraph (16) of this subsection. To the extent possible, the systems changes should be designed to ensure that the 60-day period following a mass transition, when a customer switches away from a POLR provider, the switch transaction is processed as an unprotected, out-of-cycle switch, regardless of how the switch was submitted.

(15) In the event of a transition to a POLR provider or away from a POLR provider to a REP of choice, the switch notification notice detailed in §25.474(l) of this title (relating to Selection of Retail Electric Provider) is not required.

(16) In a mass transition event, the ERCOT initiated transactions shall request an out-of-cycle meter read for the associated ESI IDs for a date two calendar days after the calendar date ERCOT initiates such transactions to the TDU. If an ESI ID does not have the capability to be read in a fashion other than a physical meter read, the out-of-cycle meter read may be estimated. An estimated meter read for the purpose of a mass transition to a POLR provider shall not be considered a break in a series of consecutive months of estimates, but shall not be considered a month in a series of consecutive estimates performed by the TDU. A TDU shall create a regulatory asset for the TDU fees associated with a mass transition of customers to a POLR provider pursuant to this subsection. Upon review of reasonableness and necessity, a reasonable level of amortization of such regulatory asset shall be included as a recoverable cost in the TDU's rates in its next rate case or such other rate recovery proceeding as deemed necessary. The TDU shall not bill as a discretionary charge, the costs included in this regulatory asset, which shall consist of the following:

(A) fees for out-of-cycle meter reads associated with the mass transition of customers to a POLR provider; and

(B) fees for the first out-of-cycle meter read provided to a customer who transfers away from a POLR provider, when the out-of-cycle meter read is performed within 60 calendar days of the date of the mass transition and the customer is identified as a transitioned customer.

(17) In the event the TDU estimates a meter read for the purpose of a mass transition, the TDU shall perform a true-up evaluation of each ESI ID after an actual meter reading is obtained. Within 10 days after the actual meter reading is obtained, the TDU shall calculate the actual average kWh usage per day for the time period from the most previous actual meter reading occurring prior to the estimate for the purpose of a mass transition to the most current actual meter reading occurring after the estimate for the purpose of mass transition. If the average daily estimated usage sent to the exiting REP is more than 50% greater than or less than the average actual kWh usage per day, the TDU shall promptly cancel and re-bill both the exiting REP and the POLR using the average actually daily usage.

(q) **Termination of POLR service provider status.**

(1) The commission may revoke a REP's POLR status after notice and opportunity for hearing:

(A) If the POLR provider fails to maintain REP certification;

(B) If the POLR provider fails to provide service in a manner consistent with this section;

(C) The POLR provider fails to maintain appropriate financial qualifications; or

(D) For other good cause.

(2) If an LSP defaults or has its status revoked before the end of its term, after a review of the eligibility criteria, the commission staff designee shall, as soon as practicable, designate the next eligible REP, if any, as an LSP, based on the criteria in subsection (j) of this section.

(3) At the end of the POLR service term, the outgoing LSP shall continue to serve customers who have not selected another REP.

(r) **Electric cooperative delegation of authority**. An electric cooperative that has adopted customer choice may select to delegate to the commission its authority to select POLR providers under PURA §41.053(c) in its certificated service area in accordance with this section. After notice and opportunity for comment, the commission shall, at its option, accept or reject such delegation of authority. If the commission accepts the delegation of authority, the following conditions shall apply:

(1) The board of directors shall provide the commission with a copy of a board resolution authorizing such delegation of authority;

(2) The delegation of authority shall be made at least 30 calendar days prior to the time the commission issues a publication of notice of eligibility;

(3) The delegation of authority shall be for a minimum period corresponding to the period for which the solicitation shall be made;

(4) The electric cooperative wishing to delegate its authority to designate an continuous provider shall also provide the commission with the authority to apply the selection criteria and procedures described in this section in selecting the POLR providers within the electric cooperative's certificated service area; and

(5) If there are no competitive REPs offering service in the electric cooperative certificated area, the commission shall automatically reject the delegation of authority.

(s) **Reporting requirements.** Each LSP that serves customers under a rate prescribed by subsection (m)(2) of this section shall file the following information with the commission on a quarterly basis beginning January of each year in a project established by the commission for the receipt of such information. Each quarterly report shall be filed within 30 calendar days of the end of the quarter.

(1) For each month of the reporting quarter, each LSP shall report the total number of new customers acquired by the LSP under this section and the following information regarding these customers:

(A) The number of customers from whom a deposit was requested pursuant to the provisions of §25.478 of this title, and the average amount of deposit requested;

(B) The number of customers from whom a deposit was received, including those who entered into deferred payment plans for the deposit, and the average amount of the deposit;

(C) The number of customers whose service was physically disconnected pursuant to the provisions of §25.483 of this title (relating to Disconnection of Service) for failure to pay a required deposit; and

(D) Any explanatory data or narrative necessary to account for customers that were not included in either subparagraph (B) or (C) of this paragraph.

(2) For each month of the reporting quarter each LSP shall report the total number of customers to whom a disconnection notice was issued pursuant to the provisions of §25.483 of this title and the following information regarding those customers:

(A) The number of customers who entered into a deferred payment plan, as defined by §25.480(j) of this title (relating to Bill Payment and Adjustments) with the LSP;

(B) The number of customers whose service was physically disconnected pursuant to §25.483 of this title;

(C) The average amount owed to the LSP by each disconnected customer at the time of disconnection; and

(D) Any explanatory data or narrative necessary to account for customers that are not included in either subparagraph (A) or (B) of this paragraph.

(3) For the entirety of the reporting quarter, each LSP shall report, for each customer that received POLR service, the TDU and customer class associated with the customer's ESI ID, the number of days the customer received POLR service, and whether the customer is currently the LSP's customer.

(t) **Notice of transition to POLR service to customers.** When a customer is moved to POLR service, the customer shall be provided notice of the transition by ERCOT, the REP transitioning the customer, and the POLR provider. The ERCOT notice shall be provided within two days of the time ERCOT and the transitioning REP know that the customer shall be transitioned and customer contact information is available. If ERCOT cannot provide notice to customers within two days, it shall provide notice as soon as practicable. The POLR provider shall provide the notice required by paragraph (3) of this subsection to commission staff at least 48 hours before it is provided to customers, and shall provide the notice to transitioning customers as soon as practicable. The POLR provider shall email the notice to the commission staff members designated for receipt of the notice.

(1) ERCOT notice methods shall include a post-card, containing the official commission seal with language and format approved by the commission. ERCOT shall notify transitioned customers with an automated phone-call and email to the extent the information to contact the customer is available pursuant to subsection (p)(6) of this section. ERCOT shall study the effectiveness of the notice methods used and report the results to the commission.

(2) Notice by the REP from which the customer is transferred shall include:

(A) The reason for the transition;

(B) A contact number for the REP;

(C) A statement that the customer shall receive a separate notice from the POLR provider that shall disclose the date the POLR provider shall begin serving the customer;

(D) Either the customer's deposit plus accrued interest, or a statement that the deposit shall be returned within seven days of the transition;

(E) A statement that the customer can leave the assigned service by choosing a competitive product or service offered by the POLR provider, or another competitive REP, as well as the following statement: "If you would like to see offers from different retail electric providers, please access www.powertochoose.org, or call toll-free 1-866-PWR-4-TEX (1-866-797-4839) for a list of providers in your area;"

(F) For residential customers, notice from the commission in the form of a bill insert or a bill message with the header "An Important Message from the Public Utility Commission Regarding Your Electric Service" addressing why the customer has been transitioned to another REP, the continuity of service purpose, the option to choose a different competitive provider, and information on competitive markets to be found at www.powertochoose.org, or toll-free at 1-866-PWR-4-TEX (1-866-797-4839);

(G) If applicable, a description of the activities that the REP shall use to collect any outstanding payments, including the use of consumer reporting agencies, debt collection agencies, small claims court, and other remedies allowed by law, if the customer does not pay or make acceptable payment arrangements with the REP; and

(H) Notice to the customer that after being transitioned to POLR service, the customer may accelerate a switch to another REP by requesting a special or out-of-cycle meter read.

(3) Notice by the POLR provider shall include:

(A) The date the POLR provider began or shall begin serving the customer and a contact number for the POLR provider;

(B) A description of the POLR provider's rate for service. In the case of a notice from an LSP that applies the pricing of subsection (m)(2) of this section, a statement that the price is generally higher than available competitive prices, that the price is unpredictable, and that the exact rate for each billing period shall not be determined until the time the bill is prepared;

(C) The deposit requirements of the POLR provider and any applicable deposit waiver provisions and a statement that, if the customer chooses a different competitive product or service offered by the POLR provider, a REP affiliated with the POLR provider, or another competitive REP, a deposit may be required;

(D) A statement that the additional competitive products or services may be available through the POLR provider, a REP affiliated with the POLR provider, or another competitive REP, as well as the following statement: "If you would like to choose a different retail electric provider, please access www.powertochoose.org, or call toll-free 1-866-PWR-4-TEX (1-866-797-4839) for a list of providers in your area;"

(E) The applicable Terms of Service and Electricity Facts Label (EFL); and

(F) For residential customers that are served by an LSP under a rate prescribed by subsection (m)(2) of this section, a notice to the customer that after being transitioned to service from a POLR provider, the customer may accelerate a switch to another REP by requesting a special or out-of-cycle meter read.

(u) **Market notice of transition to POLR service.** ERCOT shall notify all affected Market Participants and the Retail Market Subcommittee (RMS) email listserv of a mass transition event within the same day of an initial mass-transition call after the call has taken place. The notification shall include the exiting REP's name, total number of ESI IDs, and estimated load.

(v) **Disconnection by a POLR provider.** The POLR provider must comply with the applicable customer protection rules as provided for under Subchapter R of this chapter, except as otherwise stated in this section. To ensure continuity of service, service under this section shall begin when the customer's transition to the POLR provider is complete. A customer deposit is not a prerequisite for the initiation of service under this section. Once service has been initiated, a customer deposit may be required to prevent disconnection. Disconnection for failure to pay a deposit may not occur until after the proper notice and after that appropriate payment period detailed in §25.478 of this title has elapsed, except where otherwise noted in this section.

(w) **Deposit payment assistance.**

(1) The commission staff designee shall distribute the deposit payment assistance monies to the appropriate POLRs on behalf of customers as soon as practicable.

(2) The Executive Director or staff designee shall use best efforts to provide written notice to the appropriate POLRs of the following on or before the second calendar day after the transition:

(A) a list of the ESI IDs identified by the LILA that have been or shall be transitioned to the applicable POLR (if available); and

(B) the amount of deposit payment assistance that shall be provided on behalf of a POLR customer identified by the LILA (if available).

(3) Amounts credited as deposit payment assistance pursuant to this section shall be refunded to the customer in accordance with §25.478(j) of this title.

§25.44. Privacy of Advanced Metering System Information.

An electric utility shall not sell, share, or disclose information generated, provided, or otherwise collected from an advanced metering system or meter information network, including information used to calculate charges for service, historical load data, and any other customer information; except the utility may share such information with an affiliated corporation as defined in §25.5 of this title (relating to Definitions), or other third-party entity, if the information is to be used only for the purpose of:

(1) Providing electric utility service to the customer; or
(2) Other customer-approved services.

§25.45. Low-Income List Administrator.

(a) **Purpose.** The purpose of this section is to define the responsibilities of the Low-Income List Administrator (LILA) to establish and maintain a list of eligible low-income customers and to specify the process for a retail electric provider (REP) who voluntarily seeks to obtain the low-income customer identification service from the LILA pursuant to Public Utility Regulatory Act (PURA) §17.007.

(b) **Application.** This section applies to the LILA, which has been contracted by the commission to administer aspects of the low-income customer identification process established under PURA §17.007 in cooperation with the Texas Health and Human Services Commission (HHSC). This section also applies to REPs that provide retail electric service in an area that has been opened to customer choice and that voluntarily seek to obtain the low-income customer identification service from the LILA.

(c) **Customer identification process.** The LILA shall identify eligible low-income customers through a monthly automatic identification process in cooperation with HHSC.

(1) Automatic identification is an electronic process to identify customers eligible for the low-income list by matching client data from the HHSC with residential customer-specific data from participating REPs.

(A) HHSC shall provide client information to the LILA in accordance with subsection (d)(1) of this section.

(B) REPs shall provide customer information to the LILA in accordance with subsection (d)(3) of this section.

(C) The LILA shall compare the customer information from HHSC and REPs, create files of matching customers and notify the REPs of their eligible customers.

(2) Automatically identified customers shall continue to be included on the LILA's list of eligible low-income customers as long as the customers receive qualifying HHSC benefits. Once a customer no longer receives qualifying HHSC benefits, the customer will no longer be identified by the LILA's process as an eligible low-income customer that is sent to the customer's REP.

(d) **Responsibilities.** In addition to the requirements established in this section, program responsibilities for the LILA may be established in the commission's contract with the LILA; program responsibilities for tasks undertaken by HHSC may be established in the memorandum of understanding between the commission and HHSC.

(1) **HHSC's responsibilities.** HHSC shall assist in the implementation and maintenance of the automatic enrollment process by providing a database of customers receiving qualifying HHSC benefits as detailed in the memorandum of understanding between HHSC and the commission.

(2) **The LILA's responsibilities.** The LILA shall:

(A) receive customer lists from participating REPs on at least a monthly basis through data transfer;

(B) retrieve the database of clients from HHSC on at least a monthly basis;

(C) establish a list of eligible customers, by comparing customer lists from the REPs with HHSC databases and identifying customer records that reasonably match;

(D) make available to each participating REP, on a date prescribed by the commission on at least a monthly basis, a list of eligible low-income customers; and

(E) protect the confidentiality of the customer information provided by the REPs and the client information provided by HHSC.

(3) **A participating REP's responsibilities.** A REP that voluntarily seeks to obtain a list of eligible low-income customers shall:

(A) provide residential customer information to the LILA through data transfer on a date prescribed by the commission on at least a monthly basis. The customer information shall include, to the greatest extent possible, each full name of the primary and secondary customer on each account, billing and service addresses, primary and secondary social security numbers, primary and secondary telephone numbers, Electric Service Identifier (ESI ID), service provider account number, and premise code;

(B) retrieve from the LILA the list of eligible low-income customers; and

(C) assist the LILA in working to resolve issues concerning customer eligibility.

(e) **Confidentiality of information.**

(1) The data acquired from HHSC pursuant to this section is subject to a HHSC confidentiality agreement.

(2) All data transfers from REPs to the LILA pursuant to this section shall be conducted under the terms and conditions of a standard confidentiality agreement to protect customer privacy and REPs' competitively sensitive information.

(3) The LILA may use information obtained pursuant to this section only for purposes prescribed by commission rule.

(f) **Identification of the LILA and annual election process.** The commission shall maintain a project in which REPs may elect to obtain the low-income customer identification service from the LILA. As part of this project, the commission may delegate to the executive director the authority to contract with a third-party vendor to administer aspects of the low-income customer identification process established under PURA §17.007 in cooperation with HHSC, and to negotiate the LILA's annual fee for the provision of the low-income customer identification service under PURA §17.007(d)(2).

§25.51. Power Quality.

(a) **Voltage variation.**

(1) **Standard nominal voltages to be adopted.** In addition to the nominal voltages that each electric utility has already adopted, each nominal voltage adopted by an electric utility after approval of this rule shall be a voltage indicated by the version of the American National Standards Institute, Incorporated (ANSI) Standard C84.1, *Electrical Power Systems and Equipment-Voltage Ratings (60Hz)*, or equivalent ANSI standard as later amended, in effect at the time of adoption of the nominal voltages. An electric utility may adopt different nominal voltages to serve specific customers if such action does not compromise prudent transmission and distribution system operation.

(2) **Nominal voltage limitations**. So far as technologically practicable, each electric utility shall maintain its standard distribution system nominal voltages within the limits specified in the *current version* of ANSI Standard C84.1, or equivalent ANSI standard as later amended. Each electric utility offering service at transmission voltages to customers who have their own transformation equipment shall maintain such voltages within a range of plus or minus 10% of its adopted nominal voltages. Variations in distribution system voltage in excess of the limits specified in ANSI C84.1 and transmission system voltages in excess of plus or minus 10% caused by action of the elements and infrequent and unavoidable fluctuations of short duration due to station or system operation shall not be considered violations of this subsection.

(b) **Frequency variation**. Each electric utility supplying alternating current shall adopt a standard frequency of 60 Hertz. This frequency shall be maintained within the limits stated in the current version of the North American Electric Reliability Council (NERC) operating manual, or succeeding NERC document that may subsequently replace the operating manual.

(c) **Harmonics.** In 60 Hertz electric power systems, a harmonic is a sinusoidal component of the 60 Hertz fundamental wave having a frequency that is an integral multiple of the fundamental frequency. "Excessive harmonics," in this subsection, shall mean levels of current or voltage distortion at the point of common coupling between the electric utility and the customer outside the levels recommended in the IEEE standard referenced in paragraph (1) of this section. Each electric utility shall assist every customer affected with problems caused by excessive harmonics and customers affected in exceptional cases as described in paragraph (5) of this section.

(1) **Applicable standards.** In addressing harmonics problems, the electric utility and the customer shall implement to the extent reasonably practicable and in conformance with prudent operation the practices outlined in IEEE Standard 519-1992, *IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems*, or any successor IEEE standard, to the extent not inconsistent with law, including state and federal statutes, orders, and regulations, and applicable municipal regulations.

(2) **Investigation.** After notice by a customer that it is experiencing problems caused by harmonics, or if an electric utility otherwise becomes aware of harmonics conditions adversely affecting a customer, the electric utility shall determine whether the condition constitutes excessive harmonics. If so, the electric utility shall investigate and determine the cause of the excessive harmonics.

(3) **Excessive harmonics created by customer.** If an electric utility determines that a customer has created excessive harmonics that causes or are reasonably likely to cause another customer to receive unsafe, unreliable or inadequate electric service, the electric utility shall provide written notice to the customer creating excessive harmonics. The notice shall state that the utility has determined that the customer has created an excessive harmonics condition and that the utility has explained the source and consequences of the harmonics problem. The notice shall give the customer two options to cure the problem.

(A) The electric utility may cure the problem by working on the customer's electric facilities at a mutually agreeable time and assess the repair costs to the customer.

(B) The customer may elect to cure the problem at its option and its cost, but the remedy must occur within a reasonable time, which will be specified in the notice.

(4) **Failure of the customer to remedy the problem.** Failure of the customer to remedy the problem may require the electric utility to disconnect the customer's service. The electric utility shall then remedy the excessive harmonics condition, or the electric utility may determine that the customer has remedied the condition within the time specified. In the event the customer refuses to allow the electric utility to remedy the problem and does not stop creating excessive harmonics within the time specified, the electric utility may disconnect the customer's service. Before disconnecting pursuant to this subsection, the electric utility must provide written notice of its intent to disconnect at least five working days before doing so, unless the customer grants the utility access to its electric facilities or ceases creating excessive harmonics. The electric utility may disconnect the customer five working days after providing the notice, unless the customer grants the electric utility access to its electric facilities or ceases creating excessive harmonics.

(5) **Excessive harmonics created by an electric utility or third party.** If an electric utility determines that its operation or facilities, or the operations or facilities of a third party other than a customer, created excessive harmonics that causes or is reasonably likely to cause a customer to receive unsafe, unreliable or inadequate electric service, the electric utility shall remedy the excessive harmonics condition at the earliest practical date.

(6) **Excessive total harmonic distortion created by two or more harmonic sources within IEEE 519 limits**. If, in its investigation of a harmonics problem, an electric utility determines that two or more customers' harmonic loads are individually within IEEE 519 limits but the sum of the loads are in excess of the IEEE 519 limits, the utility may require each customer to reduce its harmonic levels beyond the limits specified in IEEE 519.

(7) **Cost responsibility.**

(A) Customer-created excessive harmonics. Electric utilities that remedy a customer-created excessive harmonics condition shall assess that customer a fee for the investigation and repair of the condition. Where a customer has remedied the condition, the electric utility shall assess the customer a fee for investigating the problem. The electric utility shall charge all applicable fees if required to disconnect the customer. An electric utility fee for investigation and repair of customer-created excessive harmonics conditions must be reasonable under the circumstances, and shall equal the electric utility's actual costs incurred, including its reasonable administrative costs.

(B) Electric utility-created and third party-created excessive harmonics. Each electric utility that created an excessive harmonics condition, or that investigated or remedied an excessive harmonics condition created by a third party other than a customer, must bear the costs incurred in investigating and remedying the condition, and shall not assess any fees to the affected customer.

(8) **Cooperatives.** In fulfilling any of the responsibilities described in this subsection, a retail distribution cooperative that is a member of a generation and transmission (G & T) cooperative may request the G & T cooperative's assistance. The retail distribution cooperative bears full responsibility for ensuring that this subsection's requirements are fulfilled.

(d) **Power quality monitoring**. Each electric utility shall provide, maintain, calibrate, and use appropriate power monitoring instruments to investigate power quality complaints from its customers and to determine the cause of disturbances and power quality problems on the utility's system. In addressing power quality monitoring, each electric utility shall implement to the extent reasonably practicable and in conformance with prudent operation the practices outlined in IEEE Standard 1159-1995, *IEEE Recommended Practice* *for Monitoring Electric Power Quality*, or any successor IEEE standard, to the extent not inconsistent with law, including state and federal statutes, orders, and regulations, and applicable municipal regulations.

(e) **Voltmeters and voltage surveys**.

(1) **Voltmeters.** Each electric utility shall provide, maintain, and use portable voltmeters for testing voltage regulation, and electric utilities serving more than 250 meters shall provide, maintain, and use one or more portable recording voltmeters. These instruments shall be of a type and capacity suited to the voltage supplied.

(2) **Voltage surveys.** Each electric utility shall make a sufficient number of voltage surveys to adequately measure the character of service furnished its customers and to satisfy the commission of its compliance with the voltage requirements. Electric utilities having recording voltmeters shall keep at least one of these voltmeters in continuous service for the same purpose.

§25.52. Reliability and Continuity of Service.

(a) **Application**. This section applies to all electric utilities as defined by the Public Utility Regulatory Act (PURA) §31.002(6) and all transmission and distribution utilities as defined by PURA §31.002(19). The term "utility" as used in this section shall mean an electric utility and a transmission and distribution utility.

(b) **General**.

(1) Every utility shall make all reasonable efforts to prevent interruptions of service. When interruptions occur, the utility shall reestablish service within the shortest possible time.

(2) Each utility shall make reasonable provisions to manage emergencies resulting from failure of service, and each utility shall issue instructions to its employees covering procedures to be followed in the event of emergency in order to prevent or mitigate interruption or impairment of service.

(3) In the event of national emergency or local disaster resulting in disruption of normal service, the utility may, in the public interest, interrupt service to other customers to provide necessary service to civil defense or other emergency service entities on a temporary basis until normal service to these agencies can be restored.

(4) Each utility shall maintain adequately trained and experienced personnel throughout its service area so that the utility is able to fully and adequately comply with the service quality and reliability standards.

(5) With regard to system reliability, no utility shall neglect any local neighborhood or geographic area, including rural areas, communities of less than 1,000 persons, and low-income areas.

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

(1) **Critical loads** — Loads for which electric service is considered crucial for the protection or maintenance of public safety; including but not limited to hospitals, police stations, fire stations, critical water and wastewater facilities, and customers with special in-house life-sustaining equipment.

(2) Interruption classifications:

(A) **Forced —** Interruptions, exclusive of major events, that result from conditions directly associated with a component requiring that it be taken out of service immediately, either automatically or manually, or an interruption caused by improper operation of equipment or human error.

(B) **Scheduled** — Interruptions, exclusive of major events, that result when a component is deliberately taken out of service at a selected time for purposes of construction, preventative maintenance, or repair. If it is possible to defer an interruption, the interruption is considered a scheduled interruption.

(C) **Outside causes —** Interruptions, exclusive of major events, that are caused by influences arising outside of the distribution system, such as generation, transmission, or substation outages.

(D) **Major events —** Interruptions that result from a catastrophic event that exceeds the design limits of the electric power system, such as an earthquake or an extreme storm. These events shall include situations where there is a loss of power to 10% or more of the customers in a region over a 24-hour period and with all customers not restored within 24 hours.

(3) **Interruption, momentary** — Single operation of an interrupting device which results in a voltage zero and the immediate restoration of voltage.

(4) **Interruption, sustained** — All interruptions not classified as momentary.

(5) **Interruption, significant —** An interruption of any classification lasting one hour or more and affecting the entire system, a major division of the system, a community, a critical load, or service to interruptible customers; and a scheduled interruption lasting more than four hours that affects customers that are not notified in advance. A significant interruption includes a loss of service to 20% or more of the system's customers, or 20,000 customers for utilities serving more than 200,000 customers. A significant interruption also includes interruptions adversely affecting a community such as interruptions of governmental agencies, military bases, universities and schools, major retail centers, and major employers.

(6) **Reliability indices**:

(A) **System Average Interruption Frequency Index (SAIFI)** -- The average number of times that a customer's service is interrupted. SAIFI is calculated by summing the number of customers interrupted for each event and dividing by the total number of customers on the system being indexed. A lower SAIFI value represents a higher level of service reliability.

(B) **System Average Interruption Duration Index (SAIDI)** -- The average amount of time a customer's service is interrupted during the reporting period. SAIDI is calculated by summing the restoration time for each interruption event times the number of customers interrupted for each event, and dividing by the total number of customers. SAIDI is expressed in minutes or hours. A lower SAIDI value represents a higher level of service reliability.

(d) **Record of interruption**. Each utility shall keep complete records of sustained interruptions of all classifications. Where possible, each utility shall keep a complete record of all momentary interruptions. These records shall show the type of interruption, the cause for the interruption, the date and time of the interruption, the duration of the interruption, the number of customers interrupted, the substation identifier, and the transmission line or distribution feeder identifier. In cases of emergency interruptions, the remedy and steps taken to prevent recurrence shall also be recorded. Each utility shall retain records of interruptions for five years.

(e) **Notice of significant interruptions**.

(1) **Initial notice**. A utility shall notify the commission, in a method prescribed by the commission, as soon as reasonably possible after it has determined that a significant interruption has occurred. The initial notice shall include the general location of the significant interruption, the approximate number of customers affected, the cause if known, the time of the event, and the estimated time of full restoration. The initial notice shall also include the name and telephone number of the utility contact person, and shall indicate whether local authorities and media are aware of the event. If the duration of the significant interruption is greater than 24 hours, the utility shall update this information daily and file a summary report.

(2) **Summary report**. Within five working days after the end of a significant interruption lasting more than 24 hours, the utility shall submit a summary report to the commission. The summary report shall include the date and time of the significant interruption; the date and time of full restoration; the cause of the interruption, the location, substation and feeder identifiers of all affected facilities; the total number of customers affected; the dates, times, and numbers of customers affected by partial or step restoration; and the total number of customer-minutes of the significant interruption (sum of the interruption durations times the number of customers affected).

(f) **Priorities for Power Restoration to Certain Medical Facilities**.

(1) A utility shall give the same priority that it gives to a hospital in the utility's emergency operations plan for restoring power after an extended power outage, as defined by Texas Water Code, §13.1395, to the following:

(A) An assisted living facility, as defined by Texas Health and Safety Code, §247.002;

(B) A facility that provides hospice services, as defined by Texas Health and Safety Code, §142.001; and

(C) A nursing facility, as defined by Texas Health and Safety Code, §242.301;

(2) The utility may use its discretion to prioritize power restoration for a facility after an extended power outage in accordance with the facility's needs and with the characteristics of the geographic area in which power must be restored.

(g) **System reliability.** Reliability Standards shall apply to each utility, and shall be limited to the Texas jurisdiction. A "reporting year" is the 12-month period beginning January 1 and ending December 31 of each year.

(1) **System-wide standards.** The standards shall be unique to each utility based on the utility's performance, and may be adjusted by the commission if appropriate for weather or improvements in data acquisition systems. The standards will be the average of the utility's performance from the later of reporting years 1998, 1999, and 2000 or the first three reporting years the utility is in operation.

(A) **SAIFI**. Each utility shall maintain and operate its electric distribution system so that its SAIFI value shall not exceed its system-wide SAIFI standard by more than 5.0%.

(B) **SAIDI**. Each utility shall maintain and operate its electric distribution system so that its SAIDI value shall not exceed its system-wide SAIDI standard by more than 5.0%.

(2) **Distribution feeder performance.** The commission will evaluate the performance of distribution feeders with ten or more customers after each reporting year. Each utility shall maintain and operate its distribution system so that no distribution feeder with ten or more customers sustains a SAIDI or SAIFI value for a reporting year that is more than 300% greater than the system average of all feeders during any two consecutive reporting years.

(3) **Enforcement.** The commission may take appropriate enforcement action, including action against a utility, if the system and feeder performance is not operated and maintained in accordance with this subsection. In determining the appropriate enforcement action, the commission shall consider:

(A) the feeder's operation and maintenance history;

(B) the cause of each interruption in the feeder's service;

(C) any action taken by a utility to address the feeder's performance;

(D) the estimated cost and benefit of remediating a feeder's performance; and

(E) any other relevant factor as determined by the commission.

§25.53. Electric Service Emergency Operations Plans.

(a) **Application.** This section applies to electric utilities (including transmission and distribution utilities), power generation companies (PGCs), retail electric providers (REPs), and the Electric Reliability Council of Texas (ERCOT), collectively referred to as "market entities," and electric cooperatives. The commission intends that a market entity or electric cooperative apply the requirements of this section in a manner that is appropriate to its particular circumstances. If a provision in this section pertaining to an emergency operation plan does not apply to a market entity or electric cooperative, the market entity or electric cooperative shall include an explanation in its emergency operations plan of why the provision does not apply.

(b) **Filing requirements.** A market entity shall file with the commission a copy of its emergency operations plan or a comprehensive summary of its emergency operations plan. A new market entity shall file with the commission a copy of its plan or a comprehensive summary before it begins commercial operations. If an electric utility, REP, or ERCOT makes a significant change to its plan, it shall file the revised plan or a revision to the comprehensive summary that appropriately addresses the change to the plan no later than 30 days after the change takes effect. If a PGC makes a significant change to its plan that occurs during the time period November 1 through April 30, it shall file that change by June 1 and for a significant change that occurs during the time period May 1 through October 31, it shall file that change by December 1. A significant change includes but is not limited to a change that has a material impact on how the market entity would respond to an emergency.

(c) **Information to be included in the emergency operations plan.**

(1) An electric utility shall include in its emergency operations plans for its transmission and distribution facilities, but is not limited to, the following:

(A) A registry of critical load customers, as defined in §25.497(a)(1)-(4) of this title (relating to Chritical Load Industrial Customers, Critical Load Public Safety Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers) directly served, if maintained by the electric cooperative. This registry shall be updated as necessary but, at a minimum, annually. The description filed with the commission shall include the location of the registry, the process for maintaining an accurate registry, the process for providing assistance to critical load customers in the event of an unplanned outage, the process for communicating with the critical load customers, and the process for training staff with respect to serving critical load customers.

(B) A communications plan that describes the procedures for communicating with the public, media, customers, and critical load customers directly served as soon as reasonably possible either before or at the onset of an emergency affecting electric service. The communications plan shall also address the electric utility's telephone system and complaint-handling procedures during an emergency.

(C) Curtailment priorities, procedures for shedding load, rotating outages, and planned interruptions.

(D) Priorities for restoration of service.

(E) A plan to ensure continuous and adequate service during a pandemic.

(F) A plan that addresses wildfire mitigation efforts.

(G) A plan for identification of potentially severe weather events, including but not limited to tornadoes, hurricanes, severely cold weather, severely hot weather, and flooding.

(H) A plan for the inventory of pre-arranged supplies for emergencies.

(I) A plan that addresses staffing during severe weather events.

(J) A hurricane plan, including evacuation and re-entry procedures (if facilities are located within a hurricane evacuation zone, as defined by the Texas Department of Public Safety's Texas Division of Emergency Management (TDEM).

(K) An affidavit from the electric utility's operations officer affirming that all relevant operating personnel of the electric utility are familiar with the contents of the emergency operations plan; and such personnel are committed to following the plan except to the extent deviations are appropriate under the circumstances during the course of an emergency.

(L) An affidavit from the electric utility that states that its transmission and distribution emergency management personnel who are designated to interact with local, state, and federal emergency management officials during emergency events have received Federal Emergency Management Agency (FEMA) National Incident Management System (NIMS) training, specifically IS-700.a, IS-800.b, IS-100.b, and IS-200.b.

(2) An electric utility that operates an electric generation facility or a PGC shall include in its emergency operations plan for its generation facilities, but is not limited to, the following:

(A) A plan that addresses severely cold weather and severely hot weather.

(B) A plan that addresses any known critical failure points, including any effects of weather design limits.

(C) A plan that addresses an emergency shortage of water.

(D) A plan for identification of potentially severe weather events, including but not limited to tornadoes, hurricanes, severely cold weather, severely hot weather, and flooding.

(E) A plan for the inventory of pre-arranged supplies for emergencies.

(F) A plan that addresses staffing during severe weather events.

(G) Checklists for generating facility personnel to address emergency events.

(H) A summary of alternative fuel and storage capacity.

(I) A plan for alternative fuel testing if the facility has the ability to utilize alternative fuels.

(J) Priorities for recovery of generation capacity.

(K) A pandemic preparedness plan.

(L) A hurricane plan, including evacuation and re-entry procedures (if facilities are located within a hurricane evacuation zone, as defined by TDEM.

(M) An affidavit from an owner, partner, officer, manager, or other official with responsibility for the PGC's operations affirming that all relevant operating personnel of the PGC are familiar with the contents of the emergency operations plan; and such personnel are committed to following the plan except to the extent deviations are appropriate under the circumstances during the course of an emergency.

(3) A REP shall include in its emergency operations plan, but is not limited to, an affidavit from an owner, partner, officer, manager, or other official with responsibility for the REP's operations affirming that the REP is prepared to implement the plan in the event of an emergency affecting the REP.

(4) ERCOT shall include in its emergency operations plan, but is not limited to, an affidavit from its operations officer affirming the following:

(A) ERCOT maintains crisis communications procedures that address communicating with the public, media, governmental entities, and market participants concerning events that affect the bulk electric system;

(B) ERCOT maintains a business continuity plan that addresses returning to normal operations after disruptions caused by a natural or manmade emergency; and

(C) ERCOT maintains a pandemic preparedness plan.

(d) **Drills.** A market entity shall conduct or participate in one or more drills annually to test its emergency procedures if its emergency procedures have not been implemented in response to an actual event within the last 12 months. If a market entity is in a hurricane evacuation zone (as defined by TDEM), at least one of the annual drills shall include a test of its hurricane plan/storm recovery plan. Following the annual drills, the market entity shall assess the effectiveness of the drill and modify its emergency operations plan as needed. An electric utility that provides retail delivery service to retail electric providers or makes retail sales to end-use customers shall notify commission staff using the method and form prescribed by commission staff, as described on the commission's website, and the appropriate TDEM District Coordinators in the electric utility's service area by email or other written form of the date, time, and location at least 30 days prior to the date of at least one drill each year.

(e) **Emergency contact information.** A market entity shall submit emergency contact information using the method and form prescribed by commission staff, as described on the commission's website. A market entity shall notify commission staff regarding a change to its emergency contact information within 30 days of the change.

(f) **Reporting requirements.** Upon request by commission staff during an activation of the State Operations Center (SOC) by TDEM, an affected market entity shall provide updates on the status of operations, outages, and restoration efforts. Updates shall continue until all event-related outages are restored or unless otherwise notified by commission staff. After an emergency event declared by the Governor of the State of Texas or the President of the United States of America, commission staff may require an affected market entity to provide an after action or lessons learned report and file it with the commission by a date specified by commission staff.

(g) **Copy available for inspection.** A market entity shall make available a complete copy of its emergency operations plan at its main office for inspection by the commission staff upon request.

(h) **Electric cooperatives.**

(1) **Application.** This subsection applies to an electric cooperative that operates generation, transmission, and/or distribution facilities

(2) **Reporting Requirements.** An electric cooperative shall file with the commission a copy of its emergency operations plan or a comprehensive summary of its emergency operations plan. A new electric cooperative shall file with the commission a copy of its plan or a comprehensive summary before it begins commercial operations. The filing shall also include an affidavit from the electric cooperative's operations officer affirming that all relevant operating personnel of the electric cooperative are familiar with the contents of the emergency operations plan; and such personnel are committed to following the plan except to the extent deviations are appropriate under the circumstances during the course of an emergency. If an electric cooperative makes a significant change to its emergency operations plan, it shall file the revised plan or a revision to the comprehensive summary that appropriately addresses the change to the plan no later than 30 days after the change takes effect. A significant change to a plan includes, but is not limited to, a change that has a material impact on how the electric cooperative would respond to an emergency.

(3) **Information to be included in the emergency operations plan.** An electric cooperative's emergency operations plan shall include, but is not limited to, the following:

(A) A registry of critical load customers, as defined in §25.497(a)(1)-(4) of this title, directly served, if maintained by the electric cooperative. This registry shall be updated as necessary but, at a minimum, annually. The description filed with the commission shall include the location of the registry, the process for maintaining an accurate registry, the process for providing assistance to critical load customers in the event of an unplanned outage, the process for communicating with the critical load customers, and the process for training staff with respect to serving critical load customers.

(B) A communications plan that describes the procedures for communicating with the public, the media, customers, and critical load customers directly served as soon as reasonably possible either before or at the onset of an emergency affecting electric service. The communications plan shall also address the electric cooperative's telephone system and complaint-handling procedures during an emergency.

(C) Curtailment priorities, procedures for shedding load, rotating outages, and planned interruptions.

(D) Priorities for restoration of service.

(E) A plan to ensure continuous and adequate service during a pandemic.

(F) A plan that addresses wildfire mitigation efforts.

(G) A plan for identification of potentially severe weather events, including but not limited to tornadoes, hurricanes, severely cold weather, severely hot weather, and flooding.

(H) A plan for the inventory of pre-arranged supplies for emergencies.

(I) A plan that addresses staffing during severe weather events.

(J) A hurricane plan, including evacuation and re-entry procedures (if facilities are located within a hurricane evacuation zone, as defined by TDEM).

(K) A statement from an electric cooperative that directly serves retail customers of whether or not its emergency management personnel who are designated to interact with local, state, and federal emergency management officials during emergency events have received Federal Emergency Management Agency (FEMA) National Incident Management System (NIMS) training, specifically IS-700.a, IS 800.b, IS – 100.b, and IS-200.b.

(4) In addition to the information required by paragraph (3) of this subsection, an electric cooperative that operates an electric generation facility shall include, but is not limited to, the following information in its emergency operations plan:

(A) A plan that addresses severely cold weather and severely hot weather.

(B) A plan that addresses any known critical failure points, including any effects of weather design limits.

(C) A plan that addresses an emergency shortage of water.

(D) Checklists for generating facility personnel to address emergency events.

(E) A summary of alternative fuel and storage capacity.

(F) A plan for alternative fuel testing if the facility has the ability to utilize alternative fuels.

(G) Priorities for recovery of generation capacity.

(5) **Preparedness Review.** An electric cooperative shall conduct one or more reviews annually of its emergency procedures with key emergency operations personnel if its emergency procedures have not been implemented in response to an actual event within the last 12 months. If the electric cooperative is in a hurricane evacuation zone, at least one of the annual reviews shall include its hurricane plan/storm recovery plan. Following the annual preparedness reviews, the electric cooperative shall assess the effectiveness of the review and modify its emergency operations plan as needed. An electric cooperative that directly serves retail customers shall notify commission staff using the method and form prescribed by commission staff, as described on the commission's website, and the appropriate TDEM District Coordinators by email or other written form, of the location, date, and time at least 30 days prior to the date of at least one review each year.

(6) **Emergency contact information.** An electric cooperative shall submit emergency contact information using the method and form prescribed by commission staff, as described on the commission's website. An electric cooperative shall notify commission staff regarding a change to its emergency contact information within 30 days of the change.

(7) **Reporting requirements.** Upon request by commission staff during an activation of the SOC by TDEM, an affected electric cooperative shall provide updates on the status of operations, outages, and restoration efforts. Updates shall continue until all event-related outages are restored or unless otherwise notified by commission staff. After an emergency event declared by the Governor of State of Texas or the President of the United States of America, commission staff may require an affected electric cooperative to provide an after action or lessons learned report and file it with the commission by a date specified by commission staff.

(8) **Copy available for inspection.** An electric cooperative shall make available a complete copy of its emergency operations plan at its main office for inspection by commission staff upon request.

(i) **Effective date.** The effective date of the amendments made to this section in Project Number 39160 is March 31, 2015 for market entities and June 1, 2015 for electric cooperatives.

§25.54. Cease And Desist Orders.

(a) **Application.** This section is applicable to electric utilities, transmission and distribution utilities, power generation companies, retail electric providers, municipally owned utilities, electric cooperatives, the independent system operator, and any other person regulated under the Public Utility Regulatory Act (PURA) Subtitle B, collectively referred to as "market participants," and shall refer to the definitions provided in PURA §11.003 and §31.002.

(b) **Authority to issue order**. The commission or the executive director, who has been authorized pursuant to subsection (c) of this section, may issue a cease and desist order if the commission or executive director determines that the alleged conduct of a market participant meets one or more of the following conditions:

(1) The conduct poses a threat to continuous and adequate electric service;

(2) The conduct is hazardous;

(3) The conduct creates an immediate danger to the public safety; or

(4) The conduct is causing or can be reasonably expected to cause an immediate injury to a customer of electric services and that the injury is incapable of being repaired or rectified by monetary compensation.

(c) **Delegation of authority.** The commission may delegate the authority to issue a cease and desist order to the executive director. The authority to issue a cease and desist order shall be delegated at an open meeting and may remain in effect for up to two years.

(d) **Procedure.** The commission must provide notice and opportunity for a hearing before issuing a cease and desist order if such notice is practicable. If such notice is not practicable, the commission may issue a cease and desist order without providing notice and opportunity for a hearing.

(1) **If notice and opportunity for a hearing is practicable.** If notice and opportunity for a hearing is practicable, the commission shall follow these procedures:

(A) **Notice and Opportunity for Hearing.** The commission shall provide notice and opportunity for hearing pursuant to Chapter 2001, Texas Government Code. The notice shall include a description of the violation(s) of PURA or this chapter that the market participant's conduct is alleged to violate and specific facts that support each allegation as reasonably believed by commission staff and a proposed order that contains a statement of the charges. Notice of a proposed order shall be given not later than the 10^{th} day before the date set for a hearing.

(B) **Hearing.** A hearing on a cease and desist order is a contested case under Chapter 2001, Texas Government Code. The commission may hold a hearing on a cease and desist order or may refer the case to be heard by the State Office of Administrative Hearings.

(C) **Service of Cease and Desist Order.** If, after notice and opportunity for a hearing, the commission issues a cease and desist order, then the commission shall serve the cease and desist order by registered or certified mail, return receipt requested, to the market participant's last known address. A cease and desist order is effective upon the earlier of receipt of actual notice or three days after the order is mailed.

(D) **Content of Cease and Desist Order.** A cease and desist order shall be served upon the market participant affected by that order and shall:

(i) Contain a statement of the charges and a description of the alleged violation(s) of PURA or this chapter that the market participant's conduct has been found to have violated and specific facts that support each violation; and

(ii) Require the market participant immediately to cease and desist from the acts, methods, or practices stated in the order.

(2) **Notice and opportunity for a hearing not practicable.** If notice and opportunity for a hearing is not practicable, the commission shall follow these procedures:

(A) **Contents of order**. A cease and desist order shall be served upon the market participant affected by that order and shall:

(i) Contain a statement of the charges and a description of the alleged violation(s) of PURA or this chapter that the market participant's conduct has been found to have violated and specific facts that support each violation as reasonably believed by commission staff;

(ii) Require the market participant immediately to cease and desist from the acts, methods, or practices stated in the order;

(iii) Notify the market participant that a request for a hearing to affirm, modify, or set aside the order must be submitted not later than the 30th day after the date the market participant receives the order; and

(iv) Contain a statement indicating that notice and an opportunity for a hearing was not practicable and state the specific reasons why notice and an opportunity for a hearing was not practicable.

(B) **Service.** Chapter 2001, Texas Government Code, does not apply to the issuance of a cease and desist order issued by the commission when notice and an opportunity for a hearing is not practicable.

(i) The commission shall serve the cease and desist order by registered or certified mail, return receipt requested, to the market participant's last known address.

(ii) A cease and desist order is effective upon the earlier of receipt of actual notice or three days after the order is mailed.

(C) **Hearing Requested.** The market participant affected by the cease and desist order may request a hearing to affirm, modify, or set aside the order. A request must be submitted not later than the 30th day after the date the market participant receives the order.

(i) If the market participant affected by a cease and desist order requests a hearing, the commission shall set the hearing date not later than the 10th day after the date the commission receives a request for a hearing or agreed to by the market participant and the commission.

(I) A hearing conducted after the issuance of a cease and desist order is a contested case under Chapter 2001, Texas Government Code. The commission may hold a hearing on a cease and desist order or may refer the case to be heard by the State Office of Administrative Hearings.

(II) Pending a hearing on a cease and desist order, the cease and desist order continues in effect unless stayed by the commission.

(III) At or following the hearing, the commission shall wholly or partly affirm, modify, or set aside the cease and desist order.

(ii) If the market participant affected by a cease and desist order does not request a hearing and the commission does not hold a hearing on the order, the order is affirmed without further action by the commission.

§25.71. General Procedures, Requirements and Penalties.

(a) **Who shall file.** The record-keeping, reporting, and filing requirements listed in this subchapter shall apply to all electric utilities operating in the State of Texas. This subchapter does not apply to municipally owned utilities or electric cooperatives unless otherwise specified. Moreover, the provisions of this subchapter are applicable to all services provided by the reporting entity.

(b) **Initial reporting.** Unless otherwise specified in a section of this subchapter, periodic reporting shall commence as follows:

(1) **Quarterly reporting.** For records, reports and other required information under this chapter, reporting shall begin with an initial filing for the first fiscal quarter for which information is available.

(2) **Annual reporting.** For all reports and other required information under this chapter, reporting shall begin with an initial filing for the most recent fiscal year ending on or prior to April 30 of the first year the record, report or other required information must be filed with the commission.

(c) **Maintenance and location of records.** Records, books, accounts, or memoranda required of an electric utility, as defined in the Public Utility Regulatory Act, §31.002(6), may be kept outside the State of Texas so long as those records, books, accounts, or memoranda are returned to the state for any inspection by the commission that is authorized by the Public Utility Regulatory Act.

(d) **Report attestation.** All reports submitted to the commission shall be attested to by an officer or manager of the electric utility or electric cooperative under whose direction the report is prepared, or if under trust or receivership, by the receiver or a duly authorized person, or if not incorporated, by the proprietor, manager, superintendent, or other official in responsible charge of the electric utility's or the electric cooperative's operation.

(e) **Information omitted from reports.** The commission may waive the reporting of any information required in this subchapter if it determines that it is either impractical or unduly burdensome for any electric utility or electric cooperative to furnish the requested information. If any such information is omitted by permission of the commission, a written explanation of the omission must be included in the report.

(f) **Due dates of reports.** All periodic reports must be received by the commission on or before the following due dates unless otherwise specified in this subchapter.

(1) **Monthly reports**: 45 days after the end of the reported period.

(2) **Quarterly reports other than shareholder reports**: 45 days after the end of the reported period.

(3) **Semi-annual reports**: 45 days after the end of the reported period.

(4) **Annual earnings report**: May 15 of each year.

(5) **Shareholder annual reports**: seven days from the date of mailing the same to shareholders.

(6) **Securities and Exchange Commission Filings**: 15 days from the initial filing date with the Securities and Exchange Commission.

(7) **Special or additional reports**: as may be prescribed by the commission.

(8) Annual reports required by §25.76 of this title (relating to Gross Receipts Assessment Report) shall be due August 15 of each year and shall reflect transactions for the previous July 1 through June 30 reporting period.

(9) Annual reports required by §25.77 of this title (relating to Payments, Compensation, and Other Expenditures) shall be due June 1 of each year and shall reflect the transactions for the most recent calendar year.

(g) **Special and additional reports.** Each electric utility shall report, on forms prescribed by the commission, special and additional information, as requested, that relates to the operation of the business of the electric utility. Electric cooperatives and municipally owned utilities may be required to file special or additional reports to the extent such information is necessary and is within the jurisdiction of the commission.

(h) **Penalty for refusal to file on time.** In addition to penalties prescribed by law, and §22.246 of the title (relating to Administrative Penalties) the commission may disallow for rate making purposes the costs related to the activities for which information was requested and not timely filed.

§25.72. Uniform System of Accounts.

(a) Each electric utility and electric cooperative shall keep uniform accounts, in accordance with this section, of all business transacted. The classification of electric utilities and electric cooperatives, index of accounts, definitions, and general instructions pertaining to each uniform system of accounts as amended from time to time shall be adhered to at all times, unless provided otherwise by these rules, or specifically permitted by the commission.

(b) **Classification**. For the purposes of accounting and reporting to the commission under this subchapter, each electric utility or electric cooperative shall be classified as follows:

(1) **Major**: electric utilities or electric cooperatives that had in each of the last three consecutive years sales or transmission service that exceeded any one or more of the following:

(A) one million megawatt-hours of total sales;

(B) 100 megawatt-hours of sales for resale;

(C) 500 megawatt-hours of gross interchange out; or

(D) 500 megawatt-hours of wheeling for others (deliveries plus losses).

(2) **Nonmajor**: electric utilities or electric cooperatives that are not classified as "major" as defined in paragraph (1) of this subsection.

(c) **System of accounts.** For the purpose of accounting and reporting to the commission, each electric utility and electric cooperative shall maintain its books and records in accordance with the following prescribed uniform system of accounts:

(1) **Major**: uniform system of accounts as adopted and amended by the Federal Energy Regulatory Commission (FERC) for major electric utilities and electric cooperatives or other commission-approved system of accounts as will be adequately informative for all regulatory purposes.

(2) **Nonmajor**: uniform system of accounts as adopted and amended by the FERC for nonmajor electric utilities and electric cooperatives or other commission-approved system of accounts as will be adequately informative for all regulatory purposes.

(d) **Other system of accounts.** When an electric utility or electric cooperative has adopted a uniform system of accounts required or approved by a state or federal agency other than the FERC (e.g., United States Department of Agriculture - Rural Utilities Service), that system of accounts may be adopted by the electric utility or electric cooperative after notification to the commission.

(e) **Merchandise accounting.** Each electric utility and electric cooperative shall keep separate accounts to show all revenues and expenses resulting from the sale or lease of appliances, fixtures, equipment, directory advertising, or other merchandise.

(f) **Accounting period**. Each electric utility and electric cooperative shall keep its books on a monthly basis so that for each month all transactions applicable thereto shall be entered in the books of the electric utility or electric cooperative.

(g) **Rules related to capitalization of construction costs**. Each electric utility and electric cooperative shall accrue allowance for funds used during construction on construction work in progress to the extent not included in rate base. In the event construction work in progress is included in rate base pursuant to the rules in §25.231(c)(2)(D) of this title (relating to Cost of Service), capitalization of allowance for funds used during construction for electric utilities and electric cooperatives shall be discontinued to the extent construction work in progress is included.

§25.73. Financial and Operating Reports.

(a) **Annual reports.**

(1) Each electric utility shall file with the commission the same annual report required by the Federal Energy Regulatory Commission (FERC). Such annual reports shall be filed with the commission on the same dates as required to be filed with the FERC. Major electric utilities that are not required to file such reports shall file with the commission an annual report on the form prescribed by the FERC.

(2) Each electric utility holding company subject to annual reporting to the Securities and Exchange Commission and each electric utility shall file with the commission three copies of its annual report to shareholders and customers. Unless included in the annual report to shareholders and customers, each electric utility shall file concurrently with the filing of such report three copies of any audited financial statements that may have been prepared on its behalf.

(b) **Annual earnings report.** Each electric utility not required to file an Annual Report pursuant to the Public Utility Regulatory Act (PURA) §39.257 shall file with the commission, on commission-prescribed forms, an earnings report providing the information required to enable the commission to properly monitor electric utilities within the state. Each transmission service provider shall file with the commission a report that will permit the commission to monitor its transmission costs and revenues pursuant to §25.193(a)(5) of this title (relating to Procedures for Modifying Transmission Rates).

(1) Each electric utility shall report information related to the most recent calendar year as specified in the instructions to the report.

(2) Each electric utility shall file three copies of the commission-prescribed earnings report and shall electronically transmit one copy of the report no later than the date prescribed in §25.71(f)(4) of this title (relating to General Procedures, Requirements and Penalties).

(c) **Securities and Exchange Commission reports**. Each electric utility and electric utility holding company subject to reporting requirements of the Securities and Exchange Commission shall file three copies of each required report with the commission. Three copies of each such report including 10-Ks, 10-Qs, 8-Ks, Annual Reports, and Registration Statements filed with the Securities and Exchange Commission shall be submitted to the commission no later than 15 days from the initial filing date with the Securities and Exchange Commission.

(d) **Duplicate information**. An electric utility shall not be required to file with the commission forms or reports which duplicate information already on file with the commission.

§25.74. Report on Change in Control, Sale of Property, Purchase of Stock, or Loan.

(a) Pursuant to Public Utility Regulatory Act (PURA) §39.262(l)-(m) and §39.915, an electric utility must report to and obtain approval of the commission before closing any transaction in which:

(1) the electric utility will be merged or consolidated with another electric utility;

(2) at least 50% of the stock of the electric utility will be transferred or sold; or

(3) a controlling interest or operational control of the electric utility will be transferred.

(b) Pursuant to PURA §14.101(a)(1), an electric utility shall not sell, acquire, or lease a plant as an operating unit or system in the State of Texas for a total consideration of more than $10 million unless the electric utility reports such transaction to the commission at least one commission working day before the transaction closes. Pursuant to PURA §37.154, if the transaction involves the sale, assignment, or lease of a certificate of convenience and necessity (CCN) or a right obtained under a CCN, the electric utility must obtain commission approval of such CCN transfer.

(c) An electric utility shall not purchase voting stock in another public utility doing business in the State of Texas unless the electric utility reports such purchase to the commission at least one commission working day before the transaction closes.

(d) An electric utility shall not loan money, stocks, bonds, notes, or other evidence of indebtedness to any person who directly or indirectly owns or holds 5% or more of the stock of the electric utility unless the electric utility reports such transaction to the commission at least one commission working day before the transaction closes. A properly filed tariff or energy efficiency plan with respect to energy conservation loans available to customers will be considered adequate reporting to the commission.

(e) This section does not apply to activities addressed by PURA §14.101(d) and §39.452(e).

(f) This section applies to any transaction addressed by this section that has not closed, except for a transaction addressed by PURA §39.262(n) or §39.915(c).

§25.76. Gross Receipts Assessment Report.

Each electric utility , electric cooperative, and retail electric provider subject to the jurisdiction of the commission shall file a gross receipts assessment report with the state comptroller reflecting those gross receipts subject to the assessment as required by the Public Utility Regulatory Act on a form prescribed by the state comptroller. This report shall be required on an annual basis for those companies that have elected to remit their assessment annually and on a quarterly basis for those companies that have elected to remit their assessment quarterly. Such reports and assessments shall be remitted in accordance with the Public Utility Regulatory Act, Chapter 16, Subchapter A.

§25.77. Payments, Compensation, and Other Expenditures.

An annual report shall be filed with the commission providing information for each of the following classes of payments, compensation (other than salary or wages subject to the withholding of federal income tax) and expenditures made relating to matters in Texas, and detailing (by payee) each expenditure (and for the purposes of this section any series of expenditures) made to a single payee exceeding $500 for:

(1) business gifts and entertainment;
(2) institutional, consumption-inducing, and other advertising expenses;
(3) public relations expenses;
(4) legislative matters, including advocacy before any legislative body;
(5) representation before any governmental agency or body, including municipalities;
(6) legal expenses not accounted for in other categories of this subsection;
(7) charitable, civic, religious, and political contributions and donations;
(8) all dues or membership fees paid, including an identification of that portion of those dues or membership fees paid to a trade association, industry group, or other organization formed to advance, or whose activities are or become primarily directed toward advancing, utility interests, which relate to activities listed in paragraphs (1)-(7) of this subsection if known following reasonable inquiry by the utility; and
(9) other expenses as deemed appropriate by the commission.

§25.78. State Agency Utility Account Information.

(a) **Application**. The requirements of this section shall apply to any electric utility, including a municipally-owned electric utility.

(b) In this section, "State agency" shall have the following meaning:
   (1) any board, commission, department, office, or other agency in the executive branch of state government that is created by the constitution or a statute of the state;
   (2) an institution of higher education as defined by the Education Code §61.003, other than a public junior college;
   (3) the legislature or a legislative agency; or
   (4) the Supreme Court of Texas, the Court of Criminal Appeals of Texas, a court of civil appeals, a state judicial agency, or the State Bar of Texas.

(c) An electric utility shall provide the information required in subsection (e) of this section for each state agency account in the prescribed form and medium. The electric utility shall obtain from the General Services Commission or its designee a copy of the field layouts and electronic format that the electric utility shall use. The General Services Commission or its designee shall notify the electric utility of any changes to the field layouts and electronic format with sufficient time for the electric utility to submit the information required by this subsection in a timely manner. Such form and medium must make the reports easy to compile and analyze in a manner which is not unreasonably costly, and to the extent possible, the General Services Commission or its designee will accommodate the electric utilities' electronic formats.

(d) An electric utility shall retain all billing records for each state agency account for at least four years from the billing date, notwithstanding any other commission rule relating to the retention of billing records that may provide for a shorter retention period.

(e) An electric utility shall:
   (1) each year file the monthly billing information for each state agency account required by this subsection within 45 days after the end of the reporting period for the six months ending with the February billing period and for the six months ending with the August billing period.
   (2) provide in the prescribed form the following information for each state agency account:
      (A) Utility name: name of the electric utility providing service;
      (B) Account Name: name of the state agency receiving service from the electric utility;
      (C) Account Number;
      (D) Account Address: the address of the facility being served by the electric utility, or, if that is not available, the service location;
      (E) SIC Code: Standard Industrial Code number applicable to facilities served at the account, if available;
      (F) Account Description: descriptive information available to the electric utility regarding the nature of the facilities served at the account, (e.g., office building, traffic signal, etc.) if available;
      (G) Rate Class: name of the rate class under which service is provided (e.g., Residential, General Service, Highway Safety Lighting, etc.);
      (H) Rate Code: the code number used by the electric utility to identify the rate class under which service is provided;
      (I) Service Voltage: the specific service voltage (e.g., 480 volts, 12,470, 69,000, etc.) if available, otherwise provide general voltage level (e.g., secondary, primary, transmission);
      (J) Read Date: the date on which the meter was read during the billing period;
      (K) Kilowatt-Hour Meter Number: the serial number for the kilowatt-hour meter;

(L) Kilowatt-Hour Multiplier: the multiplier used to determine kilowatt-hour consumption based on the meter reading;
(M) Monthly kWh: the number of kilowatt-hours used for billing purposes;
(N) Demand Meter Number: the serial number for the demand meter if different from that of the kilowatt-hour meter;
(O) Demand Meter Multiplier: the multiplier used to determine demand based on the meter reading;
(P) Demand Reading: the reading taken from the demand meter, stated in kilowatts or kilovolt-amperes;
(Q) Billing Demand: the demand amount used for billing purposes, in kilowatts or kilovolt-amperes;
(R) Metered Demand: the demand amount measured during the billing period, stated in kilowatts or kilovolt-amperes;
(S) KVAR: reactive power measurement for the billing period, if available;
(T) Power Factor: the ratio of real power (kW) to apparent power (kVa), if available;
(U) Customer Revenue: the portion of the bill related to the monthly customer charge or facilities charge, if available;
(V) Power Cost Recovery Factor (PCRF): the PCRF rate for the period that is assessed based on energy usage; the PCRF rate for the period that is assessed based on demand (if applicable); and the total PCRF charge for the period;
(W) Energy Revenue: the portion of the bill related to the monthly energy charge(s), if available;
(X) Demand Revenue: the portion of the bill related to the monthly demand charge(s), if available;
(Y) Base Revenue: the portion of the bill related to the non-fuel charges, including customer, energy, and demand charges, if available;
(Z) Fuel Revenue: the portion of the bill related to fuel and/or purchased power;
(AA) Other Revenue: the portion of the bill related to taxes or other miscellaneous charges;
(BB) Other Charges/Credits: the amount of any non-recurring charges or other credits, such as fuel credits and margin credits;
(CC) Explanation: an explanation of the nature of the charge/credit included in Other Charges/Credits;
(DD) Total Revenue: the total monthly bill, including base, fuel, and other charges;
(EE) Load Factor: the ratio of the average demand during the billing period to the maximum demand; and
(FF) Cost Per Kilowatt-Hour: the total cost during the billing period divided by the number of kilowatt-hours.

(3) provide the information required by this section to the General Services Commission or its designee by electronic transfer, if feasible, or, otherwise, by diskette. Only in cases of extreme undue hardship will it be permissible for an electric utility to provide the information in paper documents.

(f) Information provided pursuant to this section shall be subject to any protections of the Texas Government Code, Public Information Act, Chapter 552. Any request for information required by this section shall be filed with the Office of the Attorney General or its designee.

(g) The commission, electric utilities, and the Office of the Attorney General's designee, as well as representatives of interested state agencies, shall continue to evaluate the effectiveness and efficiency of the public monitoring and verification system for state agency customers provided in this section.

(h) An electric utility shall make a good faith effort to provide all the information required by this section. It is a violation of this section for any information to be omitted from the report unless a good faith reason exists for less than full compliance. Examples of good faith reasons for not providing a complete report include: technical limitations that cannot be corrected without undue expense, unavailability of the particular information on an electric utility's billing system or database, information that cannot reasonably be made available in the form requested, waiver by commission order, or written waiver by the Office of the Attorney General or its designee. Unless otherwise challenged in a complaint proceeding by the Office of the Attorney General as set forth herein, an electric utility is presumed to have made a good faith effort to provide the required information and is not required to seek any type of advance waiver. In the event an electric utility does not provide a complete report, the Office of the Attorney General may file a complaint with the commission. In any such complaint proceeding, the electric utility shall have the burden of showing the omission was in good faith.

§25.79. Equal Opportunity Reports.

(a) The term "minority group members," when used within this section, shall include only members of the following groups:
   (1) African-Americans;
   (2) American Indians;
   (3) Asian-Americans;
   (4) Hispanic-Americans and other Americans of Hispanic origin; and
   (5) women.

(b) Each electric utility that files any form with local, state or federal governmental agencies relating to equal employment opportunities for minority group members, (e.g., EEOC Form EEO-1, FCC Form 395, RUS Form 268, etc.) shall file copies of such completed form with the commission. If such form submitted by a multi-jurisdictional electric utility does not indicate Texas-specific numbers, the electric utility shall also prepare, and file with the commission, a form indicating Texas-specific numbers, in the same format and based on the numbers contained in the form previously filed with local, state or federal governmental agencies. Each electric utility shall also file copies of any other forms required to be filed with local, state or federal governmental agencies, which contain the same or similar information, such as personnel data identifying numbers and occupations of minority group members employed by the electric utility, and employment goals relating to them, if any.

(c) Any additional information relating to the matters described in this section may be submitted at the electric utility's option.

(d) Any electric utility filing with the commission any documents described in subsections (b) and (c) of this section shall file four copies of such documents with the commission's filing clerk under the project number assigned by the Public Utility Commission's Central Records Office for that year's filings. Utilities shall obtain the project number by contacting Central Records.

(e) An electric utility that files a report with local, state or federal governmental agencies and that is required by this section to file such report with the commission, must file the report by December 30 of the year it is filed with the local, state or federal agencies.

§25.80. Annual Report on Historically Underutilized Businesses.

(a) In this section, "historically underutilized business" has the same meaning as in Texas Government Code, §481.191, as it may be amended.

(b) Every electric utility shall report its use of historically underutilized businesses (HUBs) to the commission on a form approved by the commission. An electric utility may submit the report on paper, or on paper and on a diskette (in Lotus 1-2-3 (*utility name.wk*) or Microsoft Excel (*utility name.xl*) format).

(1) Each electric utility shall on or before December 30 of each year submit to the commission a comprehensive annual report detailing its use of HUBs for the four quarters ending on September 30 of the year the report is filed, using the Large Utilities HUB Report form.

(2) Each electric utility wishing to report indirect HUB procurements or HUB procurements made by the contractor of the utility may use the Supplemental HUB report form.

(3) Each electric utility shall submit a text description of how it determined which of its vendors is a HUB.

(4) Each electric utility that has more than 1,000 customers in a state other than Texas, or which purchases more than 10% of its goods and services (other than fuel, purchased power, and wheeling) from vendors not located in Texas, shall separately report by total and category all electric utility purchases, all electric utility purchases from Texas vendors, and all electric utility purchases from Texas HUB vendors. A vendor is considered a Texas vendor if its physical location is situated within the boundaries of Texas.

(5) Each electric utility shall also file any other documents it believes appropriate to convey an accurate impression of its use of HUBs.

(c) This section may not be used to discriminate against any citizen on the basis of race, nationality, color, religion, sex, or martial status.

(d) This section does not create a new cause of action, either public or private.

§25.81. Service Quality Reports.

Each electric utility shall submit annual service quality reports no later than February 14 of each year on a form prescribed by the commission.

§25.82. Fuel Cost and Use Information.

Copies of all presently effective and future fuel purchase or sale contracts shall be available for examination or filed with the commission on request. Each generating electric utility, including municipally owned generating electric utilities, shall file monthly fuel reports on forms prescribed by the commission.

§25.83. Transmission Construction Reports.

(a) **General**. Each electric utility constructing a facility that requires reporting to the commission under §25.101 of this title (relating to Certification Criteria) shall file the reports on the commission-prescribed forms. The commission may require additional facts or information other than those required in commission forms or this section. Nothing in this section should be construed as a limitation of the commission's authority as set forth in the Public Utility Regulatory Act. All reports required in this section shall be filed in a project established by the commission. Projects that shall be reported include:

(1) projects that require a Certificate of Convenience and Necessity (CCN) under §25.101(b)(3) of this title;

(2) projects that do not require a CCN as identified in §25.101(c)(3) and (5) of this title; and

(3) other transmission related projects with an estimated cost exceeding $250,000.

(b) **Reporting of projects that require a certificate.** Projects that require a CCN under §25.101(b)(3) of this title shall be included in the next scheduled monthly construction progress report following the filing of a CCN application and in all subsequent construction progress reports until the final project costs have been reported.

(c) **Reporting of projects not requiring a certificate.** The following information is required to be reported for projects that do not require a CCN under §25.101(c)(5) of this title.

(1) **Construction progress report.** Project information shall be filed in a scheduled monthly construction progress report no fewer than 45 days before construction begins and in all subsequent construction progress reports until the final project costs have been reported.

(2) **Consent.** Proof of written consent where required by §25.101(c)(5) of this title, shall be filed with the construction progress report no fewer than 45 days before construction begins. Proof of consent shall be established by an affidavit affirming that written consent was obtained from each required landowner. Construction shall not begin until such affidavit has been received by the commission.

(3) **Notice.** Direct notice shall be provided by first-class mail at least 45 days prior to the start of construction of the facilities. Notice is required to all utilities whose certificated service area is crossed by the facilities unless the facilities are being constructed to serve a utility that is singly certificated to the area where the facilities are to be constructed. Notice is required to all landowners whose property is crossed by projects that do not require a CCN under §25.101(c)(5) of this title, except notice is not required to landowners that have provided written consent. For projects that require new or additional rights-of-way, notice is required to all landowners with a habitable structure within 300 feet of the centerline of a transmission project of 230 kV or less, or within 500 feet of the centerline of a transmission project greater than 230 kV as identified on the current county tax rolls. In addition, direct mail notice is required to owners of parks and recreation areas within 1,000 feet, and airports within 10,000 feet, of the centerline of the proposed project. The direct mail notice shall include a description of the activities and contact information for both the utility and the commission.

(A) Proof of notice shall be established by an affidavit affirming that direct mail notice was sent to each required entity. The affidavit affirming notice shall be filed with the construction progress report no fewer than 45 days before construction begins. Construction shall not begin until such affidavit has been received by the commission.

(B) In the event that the utility finds that any landowner has not been notified, the utility shall immediately provide notice in the manner required by this paragraph and shall immediately notify the commission that such supplemental notice has been provided. Construction shall not commence until all issues related to notice have been resolved.

(d) **Reporting requirements for emergency projects.** The repair or reconstruction of a transmission facility due to emergency situations shall proceed without delay or prior approval of the commission. When emergency repairs with estimated costs exceeding $250,000 have been performed and power has been restored, the affected utility shall file a report describing the work performed and the estimated associated costs. This information shall be included as a project reported in a regularly scheduled construction progress report within 45 days of the completion of the repair and in all subsequent construction progress reports until the final costs have been reported.

§25.84. Reporting of Affiliate Transactions for Electric Utilities.

(a) **Purpose.** This section establishes reporting requirements for transactions between utilities and their affiliates.

(b) **Application.** This section applies to:

(1) electric utilities operating in the State of Texas as defined in the Public Utility Regulatory Act (PURA) §31.002(6), and transactions or activities between electric utilities and their affiliates, as defined in PURA §11.003(2); and

(2) transmission and distribution utilities operating in a qualifying power region in the State of Texas as defined in PURA §31.002(19) upon commission certification of a qualifying power region pursuant to PURA §39.152, and transactions or activities between transmission and distribution utilities and their affiliates, as defined in PURA §11.003(2).

(c) **Definitions.** Any terms defined in §25.272 of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates) have the same meanings herein.

(d) **Annual report of affiliate activities.** A "Report of Affiliate Activities" shall be filed annually with the commission. Using forms approved by the commission, a utility shall report activities among itself and its affiliates in accordance with the requirements in this section. The report shall be filed by June 1, and shall encompass the period from January 1 through December 31 of the preceding year.

(e) **Copies of contracts or agreements.** A utility shall reduce to writing and file with the commission copies of any contracts or agreements it has with its affiliates. The requirements of this subsection are not satisfied by the filing of an earnings report. All contracts or agreements shall be filed by June 1 of each year as attachments to the Report of Affiliate Activities required in subsection (d) of this section. In subsequent years, if no significant changes have been made to the contract or agreement, an amendment sheet may be filed in lieu of refiling the entire contract or agreement.

(f) **Tracking migration of employees.** A utility shall track and document the movement between the utility and its competitive affiliates of all employees engaged in transmission or distribution system operations, including persons employed by a service company affiliated with the utility who are engaged in transmission or distribution system operations on a day-to-day basis or have knowledge of transmission or distribution system operations. Employee migration information shall be included in the utility's Report of Affiliate Activities. The tracking information shall include an identification code for the migrating employee, the respective titles held while employed at each entity, and the effective dates of the migration.

(g) **Annual reporting of informal complaint resolution.** A utility shall report to the commission information regarding the nature and status of informal complaints handled in accordance with the utility's procedures developed pursuant to §25.272(i)(4) of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates). The information reported shall include the name of the complainant and a summary report of the complaint, including all relevant dates, companies involved, employees involved, the specific claim, and any actions taken to address the complaint. Such information on all informal complaints that were initiated or remained unresolved during the reporting period shall be included in the utility's Report of Affiliate Activities.

(h) **Reporting of deviations from the code of conduct.** A utility shall report information regarding the instances in which deviations from the code of conduct were necessary to ensure public safety and system reliability pursuant to §25.272(d)(4) of this title. The information reported shall include the nature of the circumstances requiring the deviation, the action taken by the utility and the parties involved, and the date of the deviation. Within 30 days of each deviation, the utility shall report this information to the commission and shall conspicuously post the information on its Internet site or a public electronic bulletin board for 30 consecutive calendar days. Such information shall be summarized in the utility's Report of Affiliate Activities.

(i) **Annual update of compliance plans.** Initial plans for compliance with §25.272 of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates) shall be supplied as a part of the utility's unbundling plan filed pursuant to PURA §39.051. The utility shall post a conspicuous notice of newly created affiliates and file any related updates to the utility's compliance plan on a timely basis pursuant to §25.272(i)(2) of this title. Additionally, the utility shall ensure that its annual Report of Affiliate Activities reflects all approved changes to its compliance plans, including those changes that result from the creation of new affiliates.

§25.85. Report of Workforce Diversity and Other Business Practices.

(a) **Purpose.** This section establishes annual reporting requirements for electric utilities to report its progress and efforts to improve workforce diversity and contracting opportunities for small and historically underutilized businesses from its five-year plan filed pursuant to the Public Utility Regulatory Act (PURA) §39.909(b).

(b) **Application.** This section applies to electric utilities, as defined in PURA §31.002(6) and subject to the requirements of PURA §39.909(c), doing business in the State of Texas.

(c) **Terminology.** In this section, "small business" and "historically underutilized business" have the meanings assigned by Texas Government Code §481.191.

(d) **Annual progress report of workforce and supplier contracting diversity.** An "Annual Progress Report on Five-Year Plan to Enhance Supplier and Workforce Diversity" shall be filed annually with the commission. The report shall be filed on or before December 30 of each year for the four prior quarters ending on September 30 of the year the report is filed.

(e) **Filing requirements.** Four copies of the Annual Progress Report on Five Year Plan to Enhance Supplier and Workforce Diversity shall be filed with the commission's filing clerk under the project number assigned by the Public Utility Commission's Central Records Office for that year's filings. Electric utilities shall obtain the project number by contacting Central Records. A copy of the annual report shall also be sent to the Governor, the Lieutenant Governor, the Speaker of the House of Representatives, and the African-American and Hispanic Caucus offices of the Texas Legislature.

(f) **Contents of the report.** The annual report filed with the commission pursuant to this section may be filed using the Workforce and Supplier Contracting Diversity form or an alternative format and shall contain at a minimum the following information:

- (1) An illustration of the diversity of the electric utility's workforce at the time of the report. If the electric utility is required to file an Equal Opportunity Report pursuant to §25.79 of this title (relating to Equal Opportunity Reports), a copy of that document may be attached to this report to satisfy the requirements of this paragraph.
- (2) A description of the specific progress made under the workforce diversity plan filed pursuant to PURA §39.909(b), including:
  - (A) the specific initiatives, programs, and activities undertaken during the preceding year; and
  - (B) an assessment of the success of each of those initiatives, programs, and activities.
- (3) An explanation of the electric utility's level of contracting with small and historically underutilized businesses.
- (4) The extent to which the electric utility has carried out its initiatives to facilitate opportunities for contracts or joint ventures with small and historically underutilized businesses.
- (5) A description of the initiatives, programs, and activities the electric utility will pursue during the next year to increase the diversity of its workforce and contracting opportunities for small and historically underutilized businesses.

(g) This section may not be used to discriminate against any citizen on the basis of race, nationality, color, religion, sex, or marital status.

(h) This section does not create a new cause of action, either public or private.

§25.88. Retail Market Performance Measure Reporting.

(a) **Purpose.** This section establishes reporting requirements to allow the commission to obtain information to be used for evaluation of the performance of the retail electric market in Texas.

(b) **Application.** This section applies to:

(1) Electric Reliability Council of Texas (ERCOT) as defined in Public Utility Regulatory Act (PURA) §31.002(5) and §25.5 of this title (relating to Definitions);

(2) Retail electric providers (REPs) as defined in PURA §31.002(17) and §25.5 of this title (relating to Definitions); and

(3) Transmission and distribution utilities (TDUs) operating in a qualifying power region in the State of Texas where customer choice has been introduced as defined in PURA §31.002(19) and §25.5 of this title (relating to Definitions), except transmission service providers that provide only wholesale transmission.

(c) **Filing requirements.** Using forms prescribed by the commission, a reporting entity shall report activities as required by this section. Such reports shall be filed with the commission under the project number assigned by the commission's central records office for all filings required each calendar year.

(1) Each entity shall file four copies of the printed report and any attachments in accordance with §22.71 of this title (related to Filing of Pleadings, Documents, and Other Material). Additionally, each entity shall file an electronic version of its report consistent with the commission's electronic filing standards set forth in §22.72(h) of this title (relating to Formal Requisites of Pleadings and Documents to be Filed with the Commission).

(2) A quarterly report shall be filed no later than the 45th day following the end of the preceding quarterly reporting period. Quarterly periods shall begin on January 1, April 1, July 1, and October 1.

(3) The reporting entity may designate information that it considers to be confidential. A reporting entity must file as confidential any information relating specifically to any other entity unless the commission has determined that such information is not competitively sensitive or the disclosing entity has given the reporting entity express written permission to release such information publicly. Information designated as confidential shall be processed in accordance with §22.71 of this title and the requirements of commission rules pertaining to information received from ERCOT.

(d) **Key performance indicators.** Reporting entities shall report on the following key performance indicators on a quarterly basis:

(1) **Competitive market indicators.** These measures will allow the commission to assess the activity in the competitive market through the number of customers and corresponding load served by non-affiliated REPs and the number of active REPs.

(2) **Technical market mechanics**. These measures will allow the commission to assess whether the technical systems of the reporting entities are functioning properly to perform market transactions necessary for a customer to select a REP and to receive timely electric service with accurate and timely bills for that service.

(e) **Supporting documentation**. Each performance measures report shall include:

(1) **Analysis.** The reporting entity shall include an analysis of its data and performance for the reporting period with a comparison to performance in the previous period.

(2) **Report attestation.** All reports submitted to the commission shall be attested to by an owner, partner, officer, or manager of the reporting entity under whose direction the report is prepared.

The attestation shall also verify that an internal review was conducted to confirm the accuracy of the information contained in the performance measures report.

(3) **Supporting documents available for inspection.** All supporting documents, including records, books, and memoranda shall be made available at the reporting entity's main office for inspection by the commission or its designee upon request. Supporting documents shall be maintained for a period of 24 months after the report date. Supporting documents may be kept outside the State of Texas so long as those records are returned to the State for any inspection requested by the commission or its designee.

(4) **Waiver of certain information.** The commission may waive the reporting of any information required in this subchapter if it determines that it is either impractical or unduly burdensome for the reporting entity to furnish the requested information. If any such information is omitted by commission waiver, a written explanation of the omission and a copy of the waiver must be included in the report.

(f) **Other reports**. Reporting entities may be required to submit special reports to allow the commission to analyze the changing dynamics of the retail electric market or to obtain information on specific issues that may require additional diagnostic review.

(1) **Supplemental information requested by the commission**. Upon request by the commission or its designee, a reporting entity shall provide any special and additional information that relates to its performance measures report. Such request shall specify a time for the reporting entity to respond that is reasonable in consideration of the information requested.

(2) **Additional reports requested through ERCOT**. Reporting entities may be required to provide to ERCOT, or groups operating under the authority of ERCOT, special and additional information that relates to market performance for specific analytical or diagnostic purposes.

(g) **Enforcement by the commission.**

(1) **Failure to timely file accurate report**. The commission may impose all applicable administrative penalties pursuant to PURA, Chapter 15, Subchapter B, consistent with §22.246 of this title (relating to Administrative Penalties) for failure of a reporting entity to timely file an accurate performance measures report.

(2) **Technical market mechanics**.

(A) **Prohibited conduct**. Each entity shall complete within the parameters set forth in the ERCOT Protocols and/or the Standard Tariff for Retail Delivery Service pursuant to §25.214 of this title (relating to Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities), at least 98% of all its technical market transactions in each transaction category identified in the filing package.

(B) **Performance-improvement plan.** Prior to imposing any penalty for a violation of subparagraph (A) of this paragraph, the commission or its designee shall meet with the reporting entity and develop a performance-improvement plan. The performance-improvement plan shall contain specific goals and timeframes for improving performance and shall be reasonable in view of all relevant circumstances.

(C) **Penalties.** If a reporting entity violates subparagraph (A) of this paragraph and fails to meet the performance required in a performance-improvement plan, the commission may impose the following penalties, as appropriate:

(i) Administrative penalties under PURA, Chapter 15, Subchapter B, consistent with §22.246 of this title;

(ii) Any penalty against ERCOT as established by commission rule and as authorized by PURA §39.151; or

(iii) Suspension, revocation, or amendment of a REP's certificate or registration as authorized by PURA §39.356 and §25.107 of this title (relating to Certification of Retail Electric Providers (REPs)).

(3) **Factors to be considered.** In assessing penalties pursuant to paragraphs (1) and (2) of this subsection, the commission shall consider the following factors:

(A) The reporting entity's prior history of performance;

(B) The reporting entity's efforts to improve performance;

(C) Whether the penalty is likely to improve performance; and

(D) Such other factors deemed appropriate and material to the particular circumstances.

(h) **Public information.** The commission may produce a summary report on the performance measures using the information collected as a result of these reporting requirements. Any such report shall be public information. The commission may provide the reports to any interested entity and post the reports on the commission's Internet website.

(i) **Commission review**. The commission may evaluate the reporting requirements as necessary to determine if modifications to the performance measures are necessary due to changing market conditions. Such evaluation process shall include notice and opportunity for public comment.

§25.89. Report of Loads and Resources.

Each transmission service customer that submits an annual report of loads and resources to the Electric Reliability Council of Texas independent system operator pursuant to §25.198(l) of this title (relating to Initiating Transmission Service) or other reliability council shall file a copy with the commission and maintain a copy of supporting documentation for five years. If no such annual report is prepared, the transmission service customer shall maintain a record of the load and resource documents prepared in the normal course of its activities for five years.

§25.90. Market Power Mitigation Plans.

(a) **Application.** An electric utility or power generation company that the commission determines owns and controls more than 20% of the installed generation capacity located in, or capable of delivering electricity to, a power region shall file a market power mitigation plan with the commission not later than December 1, 2000. An electric utility or power generation company that the commission determines owns and controls more than 20% of the installed generation capacity located in, or capable of delivering electricity to, a power region after January 1, 2002 shall file a market power mitigation plan as directed by the commission. The commission may, for good cause, waive or modify the requirement to file a market power mitigation plan, in accordance with Public Utility Regulatory Act (PURA) §39.154(b). This section does not apply to an electric utility subject to PURA §39.102(c) until the end of the utility's rate freeze.

(b) **Initial information filing.** Each utility or power generation company that owns and controls, either separately or in combination with its affiliates, more than 10,000 megawatts (MW) of electric generation capacity located in a power region that is partly or entirely within the state shall file a calculation by September 5, 2000, detailing the installed generation for its power region expected as of January 1, 2002, and showing its percentage share of the installed generation capacity located in, or capable of delivering electricity to, the power region, plus the capacity expected to be interconnected to the transmission system by January 1, 2002, less the capacity to be auctioned off pursuant to PURA §39.153, and any grandfathered facilities capacity pursuant to PURA §39.154(e). The calculation shall be made pursuant to the requirements of §25.401 of this title (relating to Share of Installed Generation Capacity). The filing shall include detailed information that will allow the commission to replicate the calculation. At a minimum, the filing must include an itemized list of all generating units that are located in, or capable of delivering electricity to, the power region and are owned and controlled by the utility or power generation company and its affiliates in the power region or capable of delivering electricity to the power region. Generating units should be identified by name, capacity rating, ownership, location, and reliability council. Capacity shall be rated according to the method established in §25.91(f) of this title (relating to Generating Capacity Reports). The filing shall also include the transmission import capacity amounts that are to be included in the numerator and the denominator of the calculation prescribed by §25.401 of this title and an explanation of how the transmission capacity amounts were determined. Any interested parties may respond to the utility filings by filing comments with the commission by September 29, 2000. By October 20, 2000, the commission will indicate which utilities, if any, exceed the 20% threshold and are required to file a market power mitigation plan on or before December 1, 2000.

(c) **Market power mitigation plan.** A market power mitigation plan is a written proposal by an electric utility or a power generation company for reducing its ownership and control of installed generation capacity as required by PURA §39.154. A market power mitigation plan may provide for:

(1) the sale of generation assets to a nonaffiliated person;
(2) the exchange of generation assets with a nonaffiliated person located in a different power region;
(3) the auctioning of generation capacity entitlements as part of a capacity auction required by PURA §39.153;
(4) the sale of the right to capacity to a nonaffiliated person for at least four years; or
(5) any reasonable method of mitigation.

(d) **Filing requirements.** The plan shall include all supporting information necessary for the commission to fully understand and evaluate the plan. On a case-by-case basis, the commission may require the electric utility or power generation company to provide any additional information the commission finds necessary to evaluate the plan. The plan submitted should incorporate information addressing the determinations listed in subsection (f) of this section.

(e) **Procedure.** The commission shall approve, modify, or reject a plan within 180 days after the date of filing. The commission may not modify the plan to require divestiture by the electric utility or power generation company.

(f) **Commission determinations.** In reaching its determination under subsection (e) of this section, the commission shall consider:

(1) the degree to which the electric utility's or power generation company's stranded costs, if any, are minimized;

(2) whether on disposition of the generation assets the reasonable value is likely to be received;

(3) the effect of the plan on the electric utility's or power generation company's federal income taxes;

(4) the effect of the plan on current and potential competitors in the generation market;

(5) whether the plan provides adequate mitigation of market power; and

(6) whether the plan is consistent with the public interest.

(g) **Request to amend or repeal mitigation plan.** An electric utility or power generation company with an approved mitigation plan may request to amend or repeal its plan. On a showing of good cause, the commission may modify or repeal the mitigation plan.

(h) **Approval date.** If an electric utility's or power generation company's market power mitigation plan is not approved before January 1 of the year it is to take effect, the commission may order the electric utility or power generation company to auction generation capacity entitlements according to PURA §39.153, subject to commission approval, of any capacity exceeding the maximum allowable capacity prescribed by PURA §39.154 until the mitigation plan is approved. An auction held under this subsection shall be held not later than 60 days after the date the order is entered.

§25.91. Generating Capacity Reports.

(a) **Application.** This section applies to each person, power generation company, municipally owned utility, electric cooperative, and river authority that owns generation facilities and offers electricity for sale in this state. This section does not apply to an electric utility subject to Public Utility Regulatory Act (PURA) §39.102(c) until the end of the utility's rate freeze.

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

(1) **Nameplate rating** – The full-load continuous rating of a generator under specified conditions as designated by the manufacturer.

(2) **Summer net dependable capability** – The net capability of a generating unit in megawatts (MW) for daily planning and operational purposes during the summer peak season, as determined in accordance with requirements of the reliability council or independent organization in which the unit operates.

(c) **Filing requirements.** Reporting parties shall file reports of generation capacity with the commission by the last working day of February each year, based on the immediately preceding calendar year. Filings shall be made using a form prescribed by the commission.

(d) **Report attestation.** A report submitted pursuant to this section shall be attested to by an owner, partner, or officer of the reporting party under whose direction the report was prepared.

(e) **Confidentiality.** The reporting party may designate information that it considers to be confidential. Information designated as confidential will be treated in accordance with the standard protective order issued by the commission applicable to generating capacity reports.

(f) **Capacity ratings.** Generating unit capacity will be reported at the summer net dependable capability rating, except as follows:

(1) Renewable resource generating units that are not dispatchable will be reported at the actual capacity value during the most recent peak season, and the report will include data supporting the determination of the actual capacity value;

(2) Generating units that will be connected to a transmission or distribution system and operating within 12 months will be rated at the nameplate rating.

(g) **Reporting requirements**.

(1) Each reporting party shall provide the following information concerning its generation capacity (in MW) and sales (in megawatt-hours (MWh)) on a power region-wide basis and for that portion of a power region in the state:

(A) total capacity of generating facilities that are connected with a transmission or distribution system;

(B) total capacity of generating facilities used to generate electricity for consumption by the person owning or controlling the facility;

(C) total capacity of generating facilities that will be connected with a transmission or distribution system and operating within 12 months;

(D) total affiliate installed generation capacity;

(E) total amount of capacity available for sale to others;

(F) total amount of capacity under contract to others;

(G) total amount of capacity dedicated to its own use;

(H) total amount of capacity that has been subject to auction as approved by the commission;

(I) total amount of capacity that will be retired within 12 months;
(J) annual capacity sales to affiliated retail electric providers (REPs);
(K) annual wholesale energy sales;
(L) annual retail energy sales; and
(M) annual energy sales to affiliate REPs;

(2) Each reporting party shall provide the following information for each generating unit it owns in whole or in part:
(A) Name;
(B) Location by county, utility service area, power region, reliability council, and, if applicable, transmission zone;
(C) Capacity rating (MW) as specified in subsection (f) of this section;
(D) Annual generation (MWh);
(E) Type of fuel or nonfuel energy resource;
(F) Technology of natural gas generator; and
(G) Date of commercial operation.

(3) Each reporting party shall identify the name and capacity rating of each generating unit that it owns that is partly owned by other parties. For each such unit, it shall identify the other owners and their respective ownership percentages.

(4) Each reporting party shall identify the name and capacity rating of each generating unit that it owns but does not control. For each such unit, it shall identify the controlling party and briefly explain the nature of the other party's control of the unit.

(5) Each reporting party shall identify the name and capacity rating of each generating unit that it owns that is located on the boundary between two power regions and able to deliver electricity directly into either power region, and shall report the total sales from each such unit for the preceding year by power region.

(6) Each reporting party that is subject to the PURA §39.154(e) shall identify the name and capacity rating of each "grandfathered" generating unit that it owns in an ozone non-attainment area. Each reporting party shall also provide copies of any applications to the Texas Natural Resources Conservation Commission (TNRCC) for a permit for the emission of air contaminants related to the grandfathered units, and it shall also provide a description of the progress it has made since its last Generating Capacity Report on achieving approval of each such TNRCC permit.

(7) Each reporting party shall identify the amount of transmission import capability that it has reserved and is available to import electricity during the summer peak into the power region from generating facilities that are owned by the reporting party or its affiliate in another power region.

(h) Upon written request by the person responsible for the commission's market oversight program, a reporting party shall provide within 15 days any information deemed necessary by that person to investigate a potential market power abuse as defined in PURA §39.157(a). In addition, the commission may request reporting parties to provide any information deemed necessary by the commission to assess market power or the development of a competitive retail market in the state, pursuant to §39.155(a). A reporting party may designate information provided to the commission as confidential in accordance with subsection (e) of this section.

§25.93. Wholesale Electricity Transaction Information.

(a) **Purpose**. The purposes of this section are to:

(1) Deter market power abuses and anticompetitive behavior by increasing wholesale market transparency with respect to bilateral contracts for delivery of electricity; and

(2) Improve the commission's ability to investigate allegations of market power abuse and anticompetitive behavior that may arise with respect to the wholesale electricity market.

(b) **Application.**

(1) This section applies to any person, municipally owned utility, electric cooperative and river authority that owns electric generation facilities and offers electricity for sale in this state. This section also applies to power marketers as defined in §25.5 of this title (relating to Definitions).

(2) This section applies to all wholesale transactions for the sale of electricity that begin or terminate in Texas, or occur entirely within Texas, including areas of the state not served by the Electric Reliability Council of Texas (ERCOT).

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

(1) **Contract**--An agreement for the wholesale provision of energy or capacity under specified prices, terms, and conditions. A contract governs the financial aspects of an electricity transaction.

(2) **Full Report--**A Wholesale Transaction Report that contains all information required by this rule including information that the Wholesale Seller of Electricity claims is confidential or Protected Information. If the Wholesale Seller of Electricity does not claim confidentiality or Protected Information status for any of the information in its Full Report then the Full Report will be treated as a Public Report.

(3) **Transaction--**The provision of a specific quantity of energy or the commitment of a specific amount of generating capacity for a specific period of time from a wholesale seller of electricity to a customer, whether pursuant to a contract, a market operated by an independent organization as defined in the Public Utility Regulatory Act §39.151(b), or any other provision of electricity or commitment of reserve capacity**.**

(4) **Protected information--**Information contained in a Wholesale Electricity Transaction Report that comports with the requirements for exception from disclosure under the Texas Public Information Act (TPIA).

(5) **Public Report--**A Wholesale Transaction Report that contains all information required by this rule except information that the Wholesale Seller of Electricity claims is confidential or Protected Information.

(6) **Wholesale seller of electricity--**Any power generation company, power marketer, municipally owned utility, electric cooperative, river authority, or other entity that sells power at wholesale.

(d) **Wholesale Electricity Transaction Reports.**

(1) Wholesale sellers of electricity shall retain information related to all wholesale electricity transactions with a point of delivery or point of receipt in Texas, including intermediate transactions involving electricity generated in Texas or electricity ultimately delivered to customers in Texas, and file with the commission, within 45 days of a request by the Executive Director or the Executive Director's designee, information related to all wholesale electricity transactions, or a requested subset of this information, for a specified period of time. Wholesale sellers of electricity shall retain information related to all wholesale electricity transactions for three years, as specified in §25.503 of this title (relating to Oversight of Wholesale Market Participants). Nothing in this section limits the ability of the commission to obtain information, or the deadline for an entity to provide information, pursuant to an investigation, contested case proceeding, or any other rule.

(2) Reports shall provide contact information for the reporting entity, information on each wholesale electricity contract, and information on each transaction of electricity from the reporting entity to another party.

(A) Contact information shall include company name, address, telephone number, and facsimile machine number, if available; name, position, and telephone number of person attesting to the report; and the time period covered by the report.

(B) Each wholesale seller of electricity must file information on each contract for electricity that is in effect during the reporting period, including those that will continue to be in effect past the end of the reporting period. Information shall include the name of purchaser, contract execution and termination dates, time period over which the contract is in effect, product type, price, and applicable information about where the power was generated, delivered, and received.

(C) Each wholesale seller of electricity must file information on each transaction. Information shall include the time period over which the transaction was conducted; applicable information about where the power was generated, delivered, and received; product name; transaction quantity; price; total transaction charges; and cross-reference to a contract reported under subparagraph (B) of this paragraph. If the period of a transaction extends outside of the reporting period, the report shall include only the portion of the transaction that occurred during the reporting period.

(D) Reporting parties may aggregate the following types of transactions:

(i) A municipally owned utility may aggregate data on the portion of its generation that it used to serve its native load. The aggregated number should be in total MWh for the reporting period, and need not include price.

(ii) A generation cooperative may aggregate data on cost-based sales to a distribution cooperative. The aggregated number should be in total MWh sold to each distribution cooperative for the reporting period, and need not include price.

(iii) A river authority may aggregate data on cost-based sales to a wholesale customer. The aggregated number should be in total MWh sold to each wholesale customer for the reporting period, and need not include price.

(iv) A qualifying facility may aggregate data on sales of electricity to a wholesale customer. The aggregated number should be in total MWh sold to each wholesale customer for the reporting period, and need not include price.

(v) Any reporting entity may aggregate data on sales of electricity or capacity to an independent system operator for balancing energy service, ancillary capacity services, or other services required by the independent system operator. This subparagraph includes sales by an entity that is qualified to sell the reporting entity's capacity and electricity to the independent system operator. The aggregated number should be in total MWh provided under each type of service for the reporting period, and need not include price.

(e) **Filing procedures**. Wholesale sellers of electricity shall file the Wholesale Electricity Transaction Reports using forms, templates, and procedures approved by the commission. The commission may also approve the use of forms and templates issued by federal agencies for reporting information similar to that required under this section. Reports shall be filed according to §22.71 of this title (relating to Filing of Pleadings, Documents and Other Materials) and §22.72 of this title (relating to Formal Requisites of Pleadings and Documents to be Filed with the Commission) except as specified in this subsection.

(1) A Full Report shall be submitted on standard-format compact disks (two copies) without a paper hard copy.

(2) If a Full Report is filed containing information that the Wholesale Seller of Electricity claims is confidential or is Protected Information, a Public Report shall also be submitted on standard-format compact disks (two copies).

(3) Information required under subsection (d)(2)(A) of this section along with attestations and other necessary documents shall be filed in hard copy form (two copies).

§25.94. Report on Infrastructure Improvement and Maintenance.

(a) **Application**. This rule applies to all electric utilities.

(b) **Reports.** By May 1st of each year, an electric utility shall file with the commission a report that contains the information described in subsection (c) of this section for the previous calendar year.

(c) The utility shall include in the report a description of the utility's activities related to:
(1) Identifying areas in its service territory that are susceptible to damage during severe weather and hardening transmission and distribution facilities in those areas;
(2) Vegetation management; and
(3) Inspecting distribution poles.

(d) Each electric utility shall include in a report required under subsection (b) of this section a summary of the utility's activities related to preparing for emergency operations.

§25.95. Electric Utility Infrastructure Storm Hardening.

(a) **Purpose**. This section is intended to ensure that each electric utility has developed a Storm Hardening Plan that provides for the implementation of cost-effective strategies to increase the ability of its transmission and distribution facilities to withstand extreme weather conditions.

(b) **Application**. This section applies to all electric utilities.

(c) **Definition**. The following term when used in this section shall have the following meaning, unless the context indicates otherwise.

Storm hardening -- All activities related to improved resiliency and restoration times, including but not limited to emergency planning, construction standards, vegetation management, or other actions before, during, or after extreme weather events.

(d) **Storm Hardening Plan Summary.** By May 1, 2011, a utility shall file with the commission a summary of its Storm Hardening Plan. The summary shall describe in detail the utility's current and future storm hardening plans over a five-year period beginning January 1, 2011. By May 1 of each subsequent year, the utility shall file a detailed summary of any material revisions to the Plan and a detailed summary of its progress in implementing the Plan. A full copy of the Plan shall be provided to the commission or commission staff upon request.

(e) **Updating and contents of Storm Hardening Plan**. A utility's Storm Hardening Plan shall be updated at least every five years and shall include, at a minimum, the utility's:

(1) Construction standards, policies, procedures, and practices employed to enhance the reliability of utility systems, including overhead and underground transmission and distribution facilities;

(2) Vegetation Management Plan for distribution facilities, including a tree pruning methodology and pruning cycle, hazard tree identification and mitigation plans, and customer education and notification practices related to vegetation management;

(3) Plans and procedures to consider infrastructure improvements for its distribution system based on smart grid concepts that provide enhanced outage resilience, faster outage restoration, and/or grid self-healing;

(4) Plans and procedures to enhance post storm damage assessment, including enhanced data collection methods for damaged poles and fallen trees;

(5) Transmission and distribution pole construction standards, pole attachment policies, and pole testing schedule;

(6) Distribution feeder inspection schedule;

(7) Plans and procedures to enhance the reliability of overhead and underground transmission and distribution facilities through the use of transmission and distribution automation;

(8) Plans and procedures to comply with the most recent National Electric Safety Code (NESC) wind loading standards in hurricane prone areas for new construction and rebuilds of the transmission and distribution system;

(9) Plans and procedures to review new construction and rebuilds to the distribution system to determine whether they should be built to NESC Grade B (or equivalent) standards;

(10) Plans and procedures to develop a damage/outage prediction model for the transmission and distribution system;

(11) Plans and procedures for use of structures owned by other entities in the provision of distribution service, such as poles owned by telecommunications utilities; and

(12) Plans and procedures for restoration of service to priority loads and for consideration of targeted storm hardening of infrastructure used to serve priority loads.

(f) **Comments.** Interested entities may file comments to the commission staff within 30 days of a utility's filing pursuant to subsection (d) of this section.

§25.96. Vegetation Management.

(a) **Application**. This section applies to an electric utility's (utility) distribution assets.

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

(1) **Distribution assets** -- The utility's facilities operating at less than 60 kilovolts (kV), excluding substations, underground facilities, and service drops, for which the utility needs to perform vegetation maintenance.

(2) **Right-of-way (ROW)** -- Land on which electric lines are located and that the utility has the right to access for the purpose of maintaining its distribution system and managing vegetation.

(3) **Scheduled vegetation maintenance** -- The anticipated vegetation management activities a utility expects to conduct during a particular budget cycle, including trimming, spraying, and removal activities.

(4) **Tree risk management** -- Planning for, assessing, monitoring, and mitigating structurally unsound trees that could threaten a utility's distribution assets.

(5) **Unscheduled vegetation maintenance** -- Responsive vegetation maintenance that can include, but is not limited to, customer-requested and utility-requested maintenance.

(c) **Vegetation management requirements under other provisions**. Compliance with this section fully satisfies the vegetation management planning and reporting requirements of §25.94(c)(2) of this title (relating to Report on Infrastructure Improvement and Maintenance) and §25.95(e)(2) of this title (relating to Electric Utility Infrastructure Storm Hardening).

(d) **Utility conformance to standards of the industry**. For any mandatory provision of any standard specified in paragraphs (1)-(3) of this subsection to which a utility's vegetation management policies do not conform, the utility shall provide a brief explanation for the deviation in its Vegetation Management Report:

(1) American National Standards Institute (ANSI) Standard Z133.1, *Arboricultural Operations – Pruning*, or successor standard;

(2) ANSI Standard A300 (Part 1) – *Tree, Shrub, and Other Woody Plant Management – Standard Practices (Pruning)*; (Part 7) – *Integrated Vegetation Management a. Utility Rights-of-way practices*; and (Part 9) – *Tree Risk Assessment a. Tree Structure Assessment;* or successor standards; and

(3) National Electrical Safety Code Section 218, or successor standard.

(e) **Vegetation Management Plan**. Each utility shall maintain a Vegetation Management Plan (Plan) that describes the utility's objectives, practices, procedures, and work specifications for its distribution assets. A full copy of the Plan shall be provided to the commission or commission staff within ten days of receipt of the request. A utility shall review and update its Plan by December 31 of each year. The Plan shall include, at a minimum, a description of the utility's:

(1) tree pruning methodology, trimming clearances, and scheduling approach;

(2) methods used to mitigate threats posed by vegetation to applicable distribution assets;

(3) tree risk management program;

(4) participation in continuing education by the utility's internal vegetation management personnel;

(5) estimate of the miles of circuits along which vegetation is to be trimmed or method for planning trimming work for the coming year;

(6) plan to remediate vegetation-caused issues on feeders which are on the worst vegetation-caused performing feeder list for the preceding calendar year's System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI); and

(7) customer education, notification, and outreach practices related to vegetation management.

(f) **Vegetation Management Report**. A utility shall file with the commission by May 1 of each year a Vegetation Management Report (Report) summarizing its Vegetation Management Plan for the current calendar year and its progress in implementing its Plan for the preceding calendar year. The Report filed May 1, 2013 does not need to contain the information required by paragraph (2) of this subsection. The Report shall include, at a minimum, the following components:

(1) A Vegetation Management Plan summary including, at a minimum, a summary of the utility's:

(A) vegetation maintenance goals and the method the utility employs to measure its progress;

(B) trimming clearances and scheduling approach;

(C) plan to remediate vegetation-caused issues on feeders that are on the vegetation-caused, worst performing feeder list for the preceding calendar year's SAIDI and SAIFI;

(D) tree risk management program;

(E) approach to monitoring, preparing for, and responding to adverse environmental conditions such as drought and wildfire danger that may impact its vegetation management policies and practices;

(F) total overhead distribution miles in its system, excluding service drops;

(G) total number of electric points of delivery;

(H) amount of vegetation-related work it plans to accomplish in the current calendar year to achieve its vegetation management goals described in subparagraph (A) of this paragraph; and

(I) vegetation management budget, divided into the categories listed in clauses (i)-(iv) of this subparagraph. The utility should, within the confines of its own budgeting practices, assign subcategories and list them under these categories where appropriate. If a utility does not budget amounts under any specific category, the utility shall provide a brief explanation of why it does not do so. The utility shall title the budget with the dates it covers and provide a total for each category or subcategory.

(i) scheduled vegetation maintenance;

(ii) unscheduled vegetation maintenance;

(iii) tree risk management; and

(iv) emergency and post-storm activities.

(2) An implementation summary for the preceding calendar year including, at a minimum, a description of:

(A) whether the utility met its vegetation maintenance goals and how its goals have changed for the coming calendar year based on the results;

(B) successes and challenges with the utility's strategy, including obstacles faced, such as property owner interference, and methods employed to overcome them;

(C) the progress and obstacles to remediating issues on the vegetation-caused, worst performing feeders list as submitted in the preceding year's Report;

(D) the number of continuing education hours logged for the utility's internal vegetation management personnel, if applicable;

(E) the amount of vegetation management work the utility accomplished to achieve its vegetation management goals described in paragraph (1)(A) of this subsection;

(F) the separate SAIDI and SAIFI scores for vegetation-caused interruptions for each month and as reported for the calendar year in its Service Quality Report filed pursuant to §25.52 of this title (relating to Reliability and Continuity of Service) and §25.81 of this title (relating to Service Quality Reports), at both the feeder and company level;

(G) the vegetation management budget, including, at a minimum:

(i) a single table with columns representing:

(I) the budget for each category and subcategory that the utility provided in the preceding year pursuant to paragraph (1)(I) of this subsection, with totals for each category and subcategory;

(II) the actual expenditures for each category and subcategory listed pursuant to subclause (I) of this clause, with totals for each category or subcategory;

(III) the percentage of actual expenditures over or under the budget for each category or subcategory listed pursuant to subclause (I) of this clause; and

(IV) the actual expenditures for the preceding reporting year for each category and subcategory listed pursuant to subclause (I) of this clause, with totals for each category or subcategory;

(ii) an explanation of the variation from the preceding year's vegetation management budget where actual expenditures in any category or subcategory fell below 98 percent or increased above 110 percent of the budget for that category;

(iii) the total vegetation management expenditures divided by the number of electric points of delivery on the utility's system, excluding service drops;

(iv) the total vegetation management expenditures, including expenditures from the storm reserve, divided by the number of customers the utility served; and

(v) the vegetation management budget from the utility's last base-rate case.

§25.101. Certification Criteria.

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

(1) **Construction and/or extension --** Shall not include the purchase or condemnation of real property for use as facility sites or right-of-way. Acquisition of right-of-way shall not be deemed to entitle an electric utility to the grant of a certificate of convenience and necessity without showing that the construction and/or extension is necessary for the service, accommodation, convenience, or safety of the public.

(2) **Generating unit --** Any electric generating facility. This section does not apply to any generating unit that is less than ten megawatts and is built for experimental purposes only.

(3) **Habitable structures** -- Structures normally inhabited by humans or intended to be inhabited by humans on a daily or regular basis. Habitable structures include, but are not limited to: single-family and multi-family dwellings and related structures, mobile homes, apartment buildings, commercial structures, industrial structures, business structures, churches, hospitals, nursing homes, and schools.

(4) **Municipal Power Agency (MPA)** -- Agency or group created under Texas Utilities Code, Chapter 163 – Joint Powers Agencies.

(5) **Municipal Public Entity (MPE)** -- A municipally owned utility (MOU) or a municipal power agency.

(6) **Prudent avoidance** -- The limiting of exposures to electric and magnetic fields that can be avoided with reasonable investments of money and effort.

(7) **Tie line** -- A facility to be interconnected to the Electric Reliability Council of Texas (ERCOT) transmission grid by a person, including an electric utility or MPE, that would enable additional power to be imported into or exported out of the ERCOT power grid.

(b) **Certificates of convenience and necessity for new service areas and facilities.** Except for certificates granted under subsection (e) of this section, the commission may grant an application and issue a certificate only if it finds that the certificate is necessary for the service, accommodation, convenience, or safety of the public, and complies with the statutory requirements in the Public Utility Regulatory Act (PURA) §37.056. The commission may issue a certificate as applied for, or refuse to issue it, or issue it for the construction of a portion of the contemplated system or facility or extension thereof, or for the partial exercise only of the right or privilege. The commission shall render a decision approving or denying an application for a certificate within one year of the date of filing of a complete application for such a certificate, unless good cause is shown for exceeding that period. A certificate, or certificate amendment, is required for the following:

(1) **Change in service area**. Any certificate granted under this section shall not be construed to vest exclusive service or property rights in and to the area certificated.

(A) Uncontested applications: An application for a certificate under this paragraph shall be approved administratively within 80 days from the date of filing a complete application if:

(i) no motion to intervene has been filed or the application is uncontested;

(ii) all owners of land that is affected by the change in service area and all customers in the service area being changed have been given direct mail notice of the application; and

(iii) commission staff has determined that the application is complete and meets all applicable statutory criteria and filing requirements, including, but not limited to, the provision of proper notice of the application.

(B) Minor boundary changes or service area exceptions: Applications for minor boundary changes or service area exceptions shall be approved administratively within 45 days of the filing of the application provided that:

(i) every utility whose certificated service area is affected agrees to the change;

(ii) all customers within the affected area have given prior consent; and

(iii) commission staff has determined that the application is complete and meets all applicable statutory criteria and filing requirements, including, but not limited to, the provision of proper notice of the application.

(2) **Generation facility.**

(A) In a proceeding involving the purchase of an existing electric generating facility by an electric utility that operates solely outside of ERCOT, the commission shall issue a final order on a certificate for the facility not later than the 181st day after the date a request for the certificate is filed with the commission under PURA §37.058(b).

(B) In a proceeding involving a newly constructed generating facility by an electric utility that operates solely outside of ERCOT, the commission shall issue a final order on a certificate for the facility not later than the 366th day after the date a request for the certificate is filed with the commission under PURA §37.058(b).

(3) **Electric transmission line.** All new electric transmission lines shall be reported to the commission in accordance with §25.83 of this title (relating to Transmission Construction Reports). This reporting requirement is also applicable to new electric transmission lines to be constructed by an MPE seeking to directly or indirectly construct, install, or extend a transmission facility outside of its applicable boundaries. For an MOU, the applicable boundaries are the municipal boundaries of the municipality that owns the MOU. For an MPA, the applicable boundaries are the municipal boundaries of the public entities participating in the MPA.

(A) Need:

(i) Except as stated below, the following must be met for a transmission line in the ERCOT power region. The applicant must present an economic cost-benefit study that includes an analysis that shows that the levelized ERCOT-wide annual production cost savings attributable to the proposed project are equal to or greater than the first-year annual revenue requirement of the proposed project of which the transmission line is a part. Indirect costs and benefits to the transmission system may be included in the cost-benefit study. The commission shall give great weight to such a study if it is conducted by the ERCOT independent system operator. This requirement also does not apply to an application for a transmission line that is necessary to meet state or federal reliability standards, including: a transmission line needed to interconnect a transmission service customer or end-use customer; or needed due to the requirements of any federal, state, county, or municipal government body or agency for purposes including, but not limited to, highway transportation, airport construction, public safety, or air or water quality.

(ii) For a transmission line not addressed by clause (i) of this subparagraph, the commission shall consider among other factors, the needs of the interconnected transmission systems to support a reliable and adequate network and to facilitate robust wholesale competition. The commission shall give great weight to:

(I) the recommendation of an organization that meets the requirement of PURA §39.151; and/or

(II) written documentation that the transmission line is needed to interconnect a transmission service customer or an end-use customer.

(B) **Routing:** An application for a new transmission line shall address the criteria in PURA §37.056(c) and considering those criteria, engineering constraints, and costs, the line shall be routed to the extent reasonable to moderate the impact on the affected community and landowners unless grid reliability and security dictate otherwise. The following factors shall be considered in the selection of the utility's alternative routes unless a route is agreed to by the utility, the landowners whose property is crossed by the proposed line, and owners of land that contains a habitable structure within 300 feet of the centerline of a transmission project of 230 kV or less, or within 500 feet of the centerline of a transmission project greater than 230 kV, and otherwise conforms to the criteria in PURA §37.056(c):

(i) whether the routes parallel or utilize existing compatible rights-of-way for electric facilities, including the use of vacant positions on existing multiple-circuit transmission lines;

(ii) whether the routes parallel or utilize other existing compatible rights-of-way, including roads, highways, railroads, or telephone utility rights-of-way;

(iii) whether the routes parallel property lines or other natural or cultural features; and

(iv) whether the routes conform with the policy of prudent avoidance.

(C) Uncontested transmission lines: An application for a certificate for a transmission line shall be approved administratively within 80 days from the date of filing a complete application if:

(i) no motion to intervene has been filed or the application is uncontested; and

(ii) commission staff has determined that the application is complete and meets all applicable statutory criteria and filing requirements, including, but not limited to, the provision of proper notice of the application.

(D) Projects deemed critical to reliability. Applications for transmission lines which have been formally designated by a PURA §39.151 organization as critical to the reliability of the system shall be considered by the commission on an expedited basis. The commission shall render a decision approving or denying an application for a certificate under this subparagraph within 180 days of the date of filing a complete application for such a certificate unless good cause is shown for extending that period.

(4) **Tie line**. An application for a tie line must include a study of the tie line by the ERCOT independent system operator. The study shall include, at a minimum, an ERCOT-approved reliability assessment of the proposed tie line. If an independent system operator intends to conduct a study to evaluate a proposed tie line or intends to provide confidential information to another entity to permit the study of a proposed tie line, the independent system operator shall file notice with the commission at least 45 days prior to the commencement of such a study or the provision of such information. This paragraph does not apply to a facility that is in service on December 31, 2014.

(c) **Projects or activities not requiring a certificate.** A certificate, or certificate amendment, is not required for the following:

(1) A contiguous extension of those facilities described in PURA §37.052;

(2) A new electric high voltage switching station, or substation;

(3) The repair or reconstruction of a transmission facility due to emergencies. The repair or reconstruction of a transmission facility due to emergencies shall proceed without delay or prior approval of the commission and shall be reported to the commission in accordance with §25.83 of this title;

(4) The construction or upgrading of distribution facilities within the electric utility's service area;

(5) Routine activities associated with transmission facilities that are conducted by transmission service providers. Nothing contained in the following subparagraphs should be construed as a limitation of the commission's authority as set forth in PURA. Any activity described in the following subparagraphs shall be reported to the commission in accordance with §25.83 of this title. The commission may require additional facts or call a public hearing thereon to determine whether a certificate of convenience and necessity is required. Routine activities are defined as follows:

(A) The modification or extension of an existing transmission line solely to provide service to a substation or metering point provided that:
(i) an extension to a substation or metering point does not exceed one mile; and
(ii) all landowners whose property is crossed by the transmission facilities have given prior written consent.

(B) The rebuilding, replacement, or respacing of structures along an existing route of the transmission line; upgrading to a higher voltage not greater than 230 kV; bundling of conductors or reconductoring of an existing transmission facility, provided that:
(i) no additional right-of-way is required; or
(ii) if additional right-of-way is required, all landowners of property crossed by the electric facilities have given prior written consent.

(C) The installation, on an existing transmission line, of an additional circuit not previously certificated, provided that:
(i) the additional circuit is not greater than 230 kV; and
(ii) all landowners whose property is crossed by the transmission facilities have given prior written consent.

(D) The relocation of all or part of an existing transmission facility due to a request for relocation, provided that:
(i) the relocation is to be done at the expense of the requesting party; and
(ii) the relocation is solely on a right-of-way provided by the requesting party.

(E) The relocation or alteration of all or part of an existing transmission facility to avoid or eliminate existing or impending encroachments, provided that all landowners of property crossed by the electric facilities have given prior written consent.

(F) The relocation, alteration, or reconstruction of a transmission facility due to the requirements of any federal, state, county, or municipal governmental body or agency for purposes including, but not limited to, highway transportation, airport construction, public safety, or air and water quality, provided that:
(i) all landowners of property crossed by the electric facilities have given prior written consent; and
(ii) the relocation, alteration, or reconstruction is responsive to the governmental request.

(6) Upgrades to an existing transmission line by an MPE that do not require any additional land, right-of-way, easement, or other property not owned by the MOU;

(7) The construction, installation, or extension of a transmission facility by an MPE that is entirely located not more than 10 miles outside of an MOU's certificated service area that occurs before September 1, 2021; or

(8) A transmission facility by an MOU placed in service after September 1, 2015, that is developed to interconnect a new natural gas generation facility to the ERCOT transmission grid and for which, on or before January 1, 2015, an MOU was contractually obligated to purchase at least 190 megawatts of capacity.

(d) **Standards of construction and operation.** In determining standard practice, the commission shall be guided by the provisions of the American National Standards Institute, Incorporated, the National Electrical Safety Code, and such other codes and standards that are generally accepted by the industry, except as modified by this commission or by municipal regulations within their jurisdiction. Each electric utility shall construct, install, operate, and maintain its plant, structures, equipment, and lines in accordance with these standards, and in such manner to best accommodate the public, and to prevent interference with service furnished by other public utilities insofar as practical.

(1) The standards of construction shall apply to, but are not limited to, the construction of any new electric transmission facilities, rebuilding, upgrading, or relocation of existing electric transmission facilities.

(2) For electric transmission line construction requiring the acquisition of new rights-of-way, electric utilities must include in the easement agreement, at a minimum, a provision prohibiting the new construction of any above-ground structures within the right-of-way. New construction of structures shall not include necessary repairs to existing structures, farm or livestock facilities, storage barns, hunting structures, small personal storage sheds, or similar structures. Utilities may negotiate appropriate exceptions in instances where the electric utility is subject to a restrictive agreement being granted by a governmental agency or within the constraints of an industrial site. Any exception to this paragraph must meet all applicable requirements of the National Electrical Safety Code.

(3) Measures shall be applied when appropriate to mitigate the adverse impacts of the construction of any new electric transmission facilities, and the rebuilding, upgrading, or relocation of existing electric transmission facilities. Mitigation measures shall be adapted to the specifics of each project and may include such requirements as:

(A) selective clearing of the right-of-way to minimize the amount of flora and fauna disturbed;

(B) implementation of erosion control measures;

(C) reclamation of construction sites with native species of grasses, forbs, and shrubs; and

(D) returning site to its original contours and grades.

(e) **Certificates of convenience and necessity for existing service areas and facilities.** For purposes of granting these certificates for those facilities and areas in which an electric utility was providing service on September 1, 1975, or was actively engaged in the construction, installation, extension, improvement of, or addition to any facility actually used or to be used in providing electric utility service on September 1, 1975, unless found by the commission to be otherwise, the following provisions shall prevail for certification purposes:

(1) The electrical generation facilities and service area boundary of an electric utility having such facilities in place or being actively engaged in the construction, installation, extension, improvement of, or addition to such facilities or the electric utility's system as of September 1, 1975, shall be limited, unless otherwise provided, to the facilities and real property on which the facilities were actually located, used, or dedicated as of September 1, 1975.

(2) The transmission facilities and service area boundary of an electric utility having such facilities in place or being actively engaged in the construction, installation, extension, improvement of, or addition to such facilities or the electric utility's system as of September 1, 1975, shall be, unless otherwise provided, the facilities and a corridor extending 100 feet on either side of said transmission facilities in place, used or dedicated as of September 1, 1975.

(3) The facilities and service area boundary for the following types of electric utilities providing distribution or collection service to any area, or actively engaged in the construction, installation, extension, improvement of, or addition to such facilities or the electric utility's system as of September 1, 1975, shall be limited, unless otherwise found by the commission, to the facilities and the area which lie within 200 feet of any point along a distribution line, which is specifically deemed to include service drop lines, for electrical utilities.

(f) **Transferability of certificates.** Any certificate granted under this section is not transferable without approval of the commission and shall continue in force until further order of the commission.

(g) **Certification forms.** All applications for certificates of convenience and necessity shall be filed on commission-prescribed forms so that the granting of certificates, both contested and uncontested, may be expedited. Forms may be obtained from Central Records.

(h) **Commission authority**. Nothing in this section is intended to limit the commission's authority to recommend or direct the construction of transmission under PURA §§35.005, 36.008, or 39.203(e).

§25.102. Coastal Management Program.

(a) **Consistency requirement.** If a transmission service provider or electric utility's request for a certificate of convenience and necessity includes transmission or generation facilities located, either in whole or in part, within the coastal management program boundary as defined in 31 T.A.C. §503.1, the transmission service provider or electric utility shall state in its initial application that: "This application includes facilities located within the coastal management program boundary as defined in 31 T.A.C. §503.1." In addition, the transmission service provider or electric utility shall indicate in its application whether any part of the proposed facilities are seaward of the Coastal Facility Designation Line as defined in 31 T.A.C. §19.2(a)(21) and identify the type (or types) of Coastal Natural Resource Area (or Areas) using the designations in 31 T.A.C. §501.3(b), that will be impacted by any part of the proposed facilities. The commission may grant a certificate for the construction of generating or transmission facilities within the coastal boundary as defined in 31 T.A.C. §503.1 only when it finds that the proposed facilities are consistent with the applicable goals and policies of the Coastal Management Program specified in 31 T.A.C. §501.14(a), or that the proposed facilities will not have any direct and significant impacts on any of the applicable coastal natural resource areas specified in 31 T.A.C. §501.3(b).

(b) **Thresholds for review.** If the proposed facilities exceed the thresholds for referral to the Coastal Coordination Council established in this section, then, in its order approving the certificate of convenience and necessity, the commission shall describe the proposed facilities and their probable impact on the applicable coastal resources specified in 31 T.A.C. §501.14(a) in the findings of fact and conclusion of law. These findings should also identify the goals and policies applied and an explanation of the basis for the commission's determination that the proposed facilities are consistent with the goals and policies of the Coastal Management Program or why the action does not adversely affect any applicable coastal natural resource specified in 31 T.A.C. §501.14(a).

(1) **Generating facilities.** In accordance with 31 T.A.C. §505.26, certificates for generating facilities subject to subsection (a) of this section may be referred to the Coastal Coordination Council for review pursuant to 31 T.A.C. §505.32 if any part of the generating facilities certificated are located seaward of the Coastal Facility Designation Line as defined in 31 T.A.C. §19.2(a)(21) and within:

(A) coastal historic areas as defined in 31 T.A.C. §501.3(b)(2);
(B) coastal preserve as defined in 31 T.A.C. §501.3(b)(3);
(C) coastal shore areas as defined in 31 T.A.C. §501.3(b)(4);
(D) coastal wetlands as defined in 31 T.A.C. §501.3(b)(5);
(E) critical dune areas as defined in 31 T.A.C. §501.3(b)(6);
(F) critical erosion areas as defined in 31 T.A.C. §501.3(b)(7);
(G) Gulf beaches as defined in 31 T.A.C. §501.3(b)(8);
(H) hard substrate reefs as defined in 31 T.A.C. §501.3(b)(9);
(I) oyster reefs as defined in 31 T.A.C. §501.3(b)(10);
(J) submerged lands as defined in 31 T.A.C. §501.3(b)(12);
(K) submerged aquatic vegetation as defined in 31 T.A.C. §501.3(b)(13); or
(L) tidal sand and mud flats as defined in 31 T.A.C. §501.3(b)(14).

(2) **Transmission facilities.** In accordance with 31 T.A.C. §505.26, certificates for transmission facilities subject to subsection (a) of this section may be referred to the Coastal Coordination Council for review pursuant to 31 T.A.C. §505.32 if any part of the transmission facilities certificated are located within Coastal Barrier Resource System Units or Otherwise Protected Areas seaward of the Coastal Facility Designation Line as defined in 31 T.A.C. §19.2(a)(21) and within:

(A) coastal wetlands as defined in 31 T.A.C. §501.3(b)(5);
(B) critical dune areas as defined in 31 T.A.C. §501.3(b)(6);
(C) Gulf beaches as defined in 31 T.A.C. §501.3(b)(8);

(D) hard substrate reefs as defined in 31 T.A.C. §501.3(b)(9);
(E) oyster reefs as defined in 31 T.A.C. §501.3(b)(10);
(F) special hazard areas as defined in 31 T.A.C. §501.3(b)(11);
(G) submerged aquatic vegetation as defined in 31 T.A.C. §501.3(b)(13); or
(H) tidal sand and mud flats as defined in 31 T.A.C. §501.3(b)(14).

(c) **Register of certificates subject to the Coastal Management Program.** The executive director of the commission or the executive director's designee shall maintain a record of all certificates subject to the Coastal Management Program and provide a copy of the record to the Coastal Coordination Council on a quarterly basis.

(d) **Notice.**

(1) **Notice of receipt.** When publishing notice of receipt of an application identified by the applicant as subject to the Coastal Management Program, the commission shall include the following statement: "This application includes facilities subject to the Coastal Management Program and must be consistent with the Coastal Management Program goals and policies."

(2) **Notice to the Coastal Coordination Council.** The commission shall place the secretary of the Coastal Coordination Council on the service list for any proceeding involving an application subject to the Coastal Management Program.

§25.105. Registration and Reporting by Power Marketers.

(a) **Purpose**. This section contains the registration and reporting requirements for a person intending to do business in Texas as a power marketer.

(b) **Applicability**.

(1) A power marketer becomes subject to this section on the date that it first buys or sells electric energy at wholesale in Texas.

(2) No later than 30 days after the date it becomes subject to this section, a power marketer shall register with the commission or provide proof that it has registered with the Federal Energy Regulatory Commission (FERC) or been authorized by the FERC to sell electric energy at market-based rates.

(c) **Initial information**. Regardless of whether it has registered with the FERC, a power marketer shall:

(1) Provide its address and the name, address, telephone number, facsimile transmission number, and e-mail address of the person to whom communications should be addressed; and the names and types of businesses of the owners (with percentages of ownership).

(2) Identify each affiliate that buys or sells electricity at wholesale in Texas; sells electricity at retail in Texas; or is an electric or municipally owned utility in Texas.

(3) Describe the location of any facility in Texas used to provide service.

(4) Provide a description of the type of service provided.

(5) Submit copies of all of its FERC registration information, filed with FERC subsequent to the effective date of this section.

(6) Submit an affidavit by an authorized person that the registrant is a power marketer.

(d) **Material change in information**. Each power marketer shall report any material change in the information provided pursuant to this section within 30 days of the change.

(e) **Commission list of power marketers**. The commission will maintain a list of power marketers registered in Texas.

§25.107. Certification of Retail Electric Providers (REPs).

(a) **Applicability.** This section applies to all persons who provide or seek to provide electric service to retail customers in an area in which customer choice is in effect and to retail customers participating in a customer choice pilot project authorized by the commission. This section does not apply to the state, political subdivisions of the state, electric cooperatives or municipal corporations, or to electric utilities providing service in an area where customer choice is not in effect. An electric cooperative or municipally owned utility participating in customer choice may offer electric energy and related services at unregulated prices directly to retail customers who have customer choice without obtaining certification as a REP.

(1) A person must obtain a certificate pursuant to this subsection before purchasing, taking title to, or reselling electricity in order to provide retail electric service.

(2) A person who does not purchase, take title to, or resell electricity in order to provide electric service to a retail customer is not a REP and may perform a service for a REP without obtaining a certificate pursuant to this section.

(3) A REP that outsources retail electric functions remains responsible under commission rules for those functions and remains accountable to applicable laws and commission rules for all activities conducted on its behalf by any subcontractor, agent, or any other entity.

(4) All filings made with the commission pursuant to this section, including a filing subject to a claim of confidentiality, shall be filed with the commission's filing clerk in accordance with the commission's Procedural Rules, Chapter 22, Subchapter E, of this title (relating to Pleadings and other Documents).

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

(1) Affiliate -- An affiliate of, or a person affiliated with, a specified person, is a person that directly, or indirectly through one or more intermediaries, controls or is controlled by, or is under the common control with, the person specified.

(2) Continuous and reliable electric service -- Retail electric service provided by a REP that is consistent with the customer's terms and conditions of service and uninterrupted by unlawful or unjustified action or inaction of the REP.

(3) Control -- The term control (including the terms controlling, controlled by and under common control with) means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through ownership of voting securities, by contract, or otherwise.

(4) Customer -- Any entity who has applied for, has been accepted for, or is receiving retail electric service from a REP on an end-use basis.

(5) Default -- As defined in a transmission and distribution utility (TDU) tariff for retail delivery service, Electric Reliability Council of Texas (ERCOT) qualified scheduling entity (QSE) agreement, or ERCOT load serving entity (LSE) agreement.

(6) Executive officer -- When used with reference to a person means its president or chief executive officer, a vice president serving as its chief financial officer, or a vice president serving as its chief accounting officer, a vice president in charge of a principal business unit, division or function, any other officer of the person who performs a policy making function for the person, or any other person who performs similar policy making functions for the person. Executive officers or subsidiaries may be deemed executive officers of the person if they perform policy making functions for the person.

(7) Guarantor -- A person providing a guaranty agreement, business financial commitment, or a credit support agreement providing financial support to a REP or applicant for REP certification pursuant to this section.

(8) Investment-grade credit rating -- A long-term unsecured credit rating of at least “Baa3” from Moody’s Investors’ Service, or “BBB-” from Standard & Poor’s or Fitch, or “BBB” from A.M. Best.

(9) Permanent employee -- An individual that is fully integrated into a REP’s business organization. A consultant is not a permanent employee.

(10) Person -- Includes an individual and any business entity, including and without limitation, a limited liability company, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, and a corporation, but does not include an electric cooperative or a municipal corporation.

(11) Principal -- An executive officer; partner; owner; director; shareholder of a privately held company; shareholder of a publicly traded company who owns more than 10 % of a class of equity securities; or a person that controls the person in question.

(12) Retail electric provider -- A person that sells electric energy to retail customers in this state. As provided in Public Utility Regulatory Act (PURA) §39.353(b), a REP is not an aggregator.

(13) Shareholder -- The term shareholder means the legal or beneficial owner of any of the equity of any business entity, including without limitation and as the context and applicable business entity requires, stockholders of corporations, members of limited liability companies and partners of partnerships.

(14) Tangible net worth -- Total shareholders’ equity, determined in accordance with generally accepted accounting principles, less intangible assets other than goodwill.

(15) Working day -- A day on which the commission is open for the conduct of business.

(c) **Application for REP certification.**

(1) A person applying for certification as a REP must demonstrate its capability of complying with this section. A person who operates as a REP or who receives a certificate under this section shall maintain compliance with this section.

(2) An application for certification shall be made on a form approved by the commission, verified by oath or affirmation, and signed by an executive officer of the applicant.

(3) Except where good cause exists to extend the time for review, the presiding officer shall issue an order finding whether an application is deficient or complete within 20 working days of filing. Deficient applications, including those without necessary supporting documentation, will be rejected without prejudice to the applicant’s right to reapply.

(4) While an application for a certificate is pending, an applicant shall inform the commission of any material change in the information provided in the application within ten working days of any such change.

(5) Except where good cause exists to extend the time for review, the commission shall enter an order approving, rejecting, or approving with modifications, an application within 90 days of the filing of the application.

(d) **REP certification requirements.** A person seeking certification under this section may apply to provide services under paragraph (1) or (2) of this subsection, and shall designate its election in the application.

(1) **Option 1.** This option is for a REP whose service offerings will be defined by geographic service area.

(A) An applicant must designate one of the following categories as its geographic service area:

(i) The geographic area of the entire state of Texas;

(ii) A specific geographic area (indicating the zip codes applicable to that area);

(iii) The service area of specific TDUs or specific municipal utilities or electric cooperatives in which competition is offered; or

(iv) The geographic area of ERCOT or other independent organization to the extent it is within Texas.

(B) A REP with a geographic service area is subject to all subsections of this section, including those pertaining to basic, financial, technical and managerial, customer protection, and reporting and changing certification requirements.

(C) The commission shall grant a certificate to an applicant proposing to provide retail electric service to a geographic service area in Texas if it demonstrates that it meets the requirements of this section.

(D) The commission shall deny an application if the configuration of the proposed geographic area would discriminate in the provision of electric service to any customer because of race, creed, color, national origin, ancestry, sex, marital status, lawful source of income, disability, or familial status; because the customer is located in an economically distressed geographic area or qualifies for low income affordability or energy efficiency services; or because of any other reason prohibited by law.

(2) **Option 2.** This option is for a REP whose service offerings will be limited to specifically identified customers, each of whom contracts for one megawatt or more of capacity. The applicant shall be certified as a REP only for purposes of serving the specified customers. The commission shall grant a certificate under this paragraph if the applicant demonstrates that it meets the requirements of this paragraph.

(A) A person seeking certification under this paragraph must file with the commission a signed, notarized affidavit from each customer, with whom it has contracted to provide one megawatt or more of capacity. The affidavit must state that the customer is satisfied that the REP meets the standards prescribed by PURA §39.352 (b)(1)-(3) and (c).

(B) The following subsections apply to REPs certified pursuant to this paragraph:

(i) Subsection (e) of this section (relating to Basic Requirements);

(ii) Subsection (f)(5) of this section (relating to Billing and Collection of Transition Charges); and

(iii) Subsection (i) of this section (relating to Requirements for Reporting and Changing Certification).

(3) **Option 3**. This option is for a REP that sells electricity exclusively to a retail customer other than a small commercial and residential customer from a distributed generation facility located on a site controlled by that customer. The following subsections do not apply to REPs certified pursuant to this paragraph: subsections (f), (g), (h), and (i)(4)-(5) of this section, except that a person seeking certification under this paragraph shall file an application with the commission that identifies a power generation company that owns the distributed generation facilities and provides the information required in subsection (g)(2)(A) of this section. A person seeking certification under this paragraph shall ensure that the distributed generation facility from which it buys electricity is owned by a power generating company (PGC) that has registered in accordance with §25.109 of this title (relating to Registration of Power Generation Companies and Self Generators), and

(A) Conforms to the requirements of §25.211 of this title (relating to Interconnection of On-Site Distributed Generation (DG)) and §25.212 of this title (relating to Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation);

(B) Is installed by a Licensed Electrician, consistent with the requirements of the Texas Department of Licensing and Regulation; and

(C) Is installed in accordance with the National Electric Code as adopted by the Texas Department of Licensing and Regulation and in compliance with all applicable local and regional building codes.

(e) **Basic requirements.**

(1) **Names on certificates.** All retail electric service shall be provided under names set forth in the granted certificate. If the applicant is a corporation, the commission shall issue the certificate in the corporate name of the applicant.

(A) No more than five assumed names may be authorized for use by any one REP at one time.

(B) Business names shall not be deceptive, misleading, vague, otherwise contrary to §25.272 of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates), or duplicative of a name previously approved for use by a REP certificate holder.

(C) If the commission determines that any requested name does not meet the requirements of subparagraph (B) of this paragraph, it shall notify the applicant that the requested name shall not be used by the REP. An application shall be dismissed if an applicant does not provide at least one suitable name.

(2) **Office requirements.** A REP shall continuously maintain an office located within Texas for the purpose of providing customer service, accepting service of process and making available in that office books and records sufficient to establish the REP's compliance with PURA and the commission's rules. The office satisfying this requirement for a REP shall have a physical address that is not a post office box and shall be a location where the above three functions can occur. To evaluate compliance with requirements in this paragraph, the commission staff may visit the office of a REP at any time during normal business hours. An applicant shall demonstrate that it has made arrangements for an office located in Texas.

(f) **Financial requirements.**

(1) **Access to capital.** A REP must meet the requirements of subparagraphs (A) or (B) of this paragraph.

(A) A REP or its guarantor electing to meet the requirements of this subparagraph must demonstrate and maintain:

(i) an investment-grade credit rating; or

(ii) tangible net worth greater than or equal to $100 million, a minimum current ratio (current assets divided by current liabilities) of 1.0, and a debt to total capitalization ratio not greater than 0.60, where all calculations exclude unrealized gains and losses resulting from valuing to market the power contracts and financial instruments used as supply hedges to serve load, and such calculations are supported by an affidavit from an executive officer of the REP attesting to the accuracy of the calculation.

(B) A REP electing to meet the requirements of this subparagraph must demonstrate shareholders' equity, determined in accordance with generally accepted accounting principles, of not less than one million dollars for the purpose of obtaining certification, and the REP or its guarantor must provide and maintain an irrevocable stand-by letter of credit payable to the commission with a face value of $500,000 for the purpose of maintaining certification.

(i) The required shareholders' equity of one million dollars shall be determined net of assets used for collateral pledged to secure the irrevocable stand-by letter of credit of $500,000.

(ii) For the period beginning on the date of certification and ending two years after the REP begins serving load, a REP shall not make any distribution or other payment to any shareholders or affiliates if, after giving effect to the distribution or other payment, the REP's shareholders' equity is less than one million dollars, net of assets used for collateral pledged to secure the irrevocable stand-by letter of credit of $500,000. The restriction on distributions or other payments contained in this subparagraph includes, but is not limited to, dividend distributions, redemptions and repurchases of equity securities, or loans to shareholders or affiliates.

(iii) A REP that began serving load on or before January 1, 2009 is not required to demonstrate the shareholders' equity required pursuant to subparagraph (B) of this paragraph, and is not subject to the restrictions on distributions or payments to shareholders or affiliates contained in subparagraph (B) of this paragraph.

(2) **Protection of customer deposits and advance payments.**

(A) A REP certified pursuant to paragraph (1)(A) of this subsection shall keep customer deposits and residential advance payments in an escrow account or segregated cash account, or provide an irrevocable stand-by letter of credit payable to the commission in an amount sufficient to cover 100% of the REPs outstanding customer deposits and residential advance payments held at the close of each month.

(B) A REP certified pursuant to paragraph (1)(B) of this subsection shall keep customer deposits and residential advance payments in an escrow account or segregated cash account, or provide an irrevocable stand-by letter of credit payable to the commission in an amount sufficient to cover 100% of the REP's outstanding customer deposits and residential advance payments held at the close of each month. For purposes of this subparagraph only, to qualify as a segregated cash account, the account must be with a financial institution whose deposits, including the deposits in the segregated cash account, are insured by the Federal Deposit Insurance Corporation, the account is designated as containing only customer deposits, the account is subject to the control or management of a provider of pervasive and comprehensive credit to the REP that is not affiliated with the REP, and the terms for managing the account protect customer deposits.

(C) In lieu of the requirements of subparagraph (B) of this paragraph, a REP certified pursuant to paragraph (1)(B) of this subsection that is providing electric service under the provisions of §25.498 of this title (relating to Retail Electric Service Using a Customer Prepayment Device or System) shall be required to keep all deposits and an amount sufficient to cover the credit balance that exceeds $50 for all customer accounts that have a credit balance exceeding $50 at the close of each month in an escrow account, or to provide an irrevocable stand-by letter of credit payable to the commission in an amount equal to or greater than the amount required to be deposited in the escrow account.

(D) Each escrow account and segregated cash account shall be reconciled no less frequently than at the close of each month to ensure that it equals or exceeds deposits and residential advance payments held as of the end of the month, and shall maintain at least that amount in the account until the next monthly reconciliation.

(E) Any irrevocable stand-by letter of credit provided pursuant to this paragraph shall be in addition to the irrevocable stand-by letter of credit required by paragraph (1)(B) of this subsection, if applicable.

(3) **Protection of TDU financial integrity.**

(A) A TDU shall not require a deposit from a REP except to secure the payment of transition charges as provided in §25.108 of this title (relating to Financial Standards for Retail Electric Providers Regarding Billing and Collection of Transition Charges), or if the REP has defaulted on one or more payments to the TDU. A TDU may impose credit conditions on a REP that has defaulted to the extent specified in its statewide standardized tariff for retail delivery service and as allowed by commission rules.

(B) A TDU shall create a regulatory asset for bad debt expenses, net of collateral posted pursuant to subparagraph (A) of this paragraph and bad debt already included in its rates, resulting from a REP's default on its obligation to pay delivery charges to the TDU. Upon a review of reasonableness and necessity, a reasonable level of amortization of such regulatory asset shall be included as a recoverable cost in the TDU's rates in its next rate case or such other rate recovery proceeding as deemed necessary.

(4) **Financial documentation required to obtain a REP certificate.** The following shall be required to demonstrate compliance with the financial requirements to obtain a REP certificate.

(A) Investment-grade credit ratings shall be documented by reports of a credit reporting agency.

(B) Tangible net worth shall be documented by the audited financial statements of the REP or its guarantor for the most recently completed calendar or fiscal year, and unaudited financial statements for the most recently completed quarter. Audited financial statements shall include the accompanying notes and the independent auditor's report. Unaudited financial statements shall include a sworn statement from an executive officer of the REP attesting to the accuracy, in all material respects, of the information provided in the unaudited financial statements. Three consecutive months of monthly statements may be submitted in lieu of quarterly statements if quarterly statements are not available. The requirement for financial statements may be satisfied by filing a copy of or by providing an electronic link to its most recent statement that contains unaudited financials filed with any agency of the federal government, including without limitation, the Securities and Exchange Commission.

(C) Shareholders' equity shall be documented by the audited and unaudited financial statements of the REP for the most recent quarter. Audited financial statements shall include the accompanying notes and the independent auditor's report. Unaudited financial statements shall include a sworn statement from an executive officer of the REP attesting to the accuracy, in all material respects, of the information provided in the unaudited financial statements. Three consecutive months of monthly statements may be submitted in lieu of quarterly statements if quarterly statements are not available. The requirement for financial statements may be satisfied by filing a copy of or by providing an electronic link to its most recent statement that contains unaudited financials filed with any agency of the federal government, including without limitation, the Securities and Exchange Commission.

(D) Segregated cash accounts shall be documented by an account statement that clearly identifies the financial institution where the account holder maintains the account, and that clearly identifies the account as an account that is designated as containing only customer deposits and residential advanced payments. Segregated cash accounts shall be maintained at a financial institution that is supervised or examined by the Board of Governors of the Federal Reserve System, the Office of the Controller of the Currency, or a state banking department, and where accounts are insured by the Federal Deposit Insurance Corporation.

(E) Escrow accounts shall be documented by the current account statement and the escrow account agreement. The escrow account agreement shall provide that the account holds customer deposits and residential advance payments only, and that the deposits are held in trust by the escrow agent and are not the property of the REP or in the REP's control unless the customer deposits are applied to a final bill or applied to satisfy unpaid amounts if allowed by the REP's terms of service. The escrow agent shall deposit the customer deposits and residential advance payments in an account at a financial institution that is supervised or examined by the Board of Governors of the Federal Reserve System, the Office of the Controller of the Currency, or a state banking department, and where accounts are insured by the Federal Deposit Insurance Corporation.

(F) Irrevocable stand-by letters of credit provided pursuant to paragraphs (1) or (2) of this subsection must be issued by a financial institution that is supervised or examined by the

Board of Governors of the Federal Reserve System, the Office of the Controller of the Currency, or a state banking department, and where accounts are insured by the Federal Deposit Insurance Corporation. The REP must use the standard form irrevocable stand-by letter of credit approved by the commission. The irrevocable stand-by letter of credit must be irrevocable for a period not less than twelve months, payable to the commission, and permit a draw to be made in part or in full. The irrevocable stand-by letter of credit must permit the commission's executive director or the designee to draw on the irrevocable stand-by letter of credit if:

(i) ERCOT performs a mass transition of the REP's customers; or

(ii) the commission issues an order revoking the REP's certificate.

(G) A REP may satisfy the requirements of paragraph (1)(A) of this subsection by relying upon a guarantor that meets one of the capital requirements of paragraph (1)(A) of this subsection, provided that:

(i) The guarantor is an affiliate of the REP and has executed and maintains the standard form guaranty agreement approved by the commission, or

(ii) The guarantor is one or more persons that are affiliates of the REP and such affiliates have executed and maintain guaranty agreements, business financial commitments, or credit support agreements that demonstrate financial support for credit or collateral requirements associated with power purchase agreements and for security associated with participation at ERCOT, or

(iii) The guarantor is a financial institution that maintains an investment-grade credit rating and has executed and maintains guaranty agreements, business financial commitments, or credit support agreements that demonstrate financial support for credit or collateral requirements associated with power purchase agreements and for security associated with participation at ERCOT, or

(iv) The guarantor is a provider of wholesale power supply to the REP, or one of such power provider's affiliates, and such person has executed and maintains guaranty agreements, business financial commitments, or credit support agreements that demonstrate financial support for credit or collateral requirements associated with a power purchase agreement and for security associated with participation at ERCOT.

(5) **Billing and collection of transition charges.** If a REP serves customers in the service area of a TDU that is subject to a financing order pursuant to PURA §39.310, the REP shall comply with §25.108 of this title.

(6) **Proceeds from an irrevocable stand-by letter of credit.**

(A) Proceeds from an irrevocable stand-by letter of credit provided under this subsection may be used to satisfy the following obligations of the REP, in the following order of priority:

(i) first, if available, to assist in the payment of the deposits to retail electric providers that volunteer to provide service in a mass transition event under §25.43 of this title (relating to Provider of Last Resort (POLR)) of low-income customers as identified by the Low-Income List Administrator pursuant to §25.45 of this title;

(ii) second, if available, to assist in the payment of deposits to retail electric providers that are designated to provide service in a mass transition event under §25.43 of this title of low-income customers as identified by the Low-Income List Administrator pursuant to §25.45 of this title;

(iii) third, for customer deposits and residential advance payments of customers;

(iv) fourth, for services provided by the independent organization related to serving customer load;

(v) fifth, for services provided by a TDU; and

(vi) sixth, for administrative penalties assessed under Chapter 15 of PURA.

(B) Proceeds from an irrevocable stand-by letter of credit provided under this subsection shall, to the extent that the proceeds are not needed to satisfy an obligation set out in subparagraph (A) of this paragraph, be paid to the REP.

(g) **Technical and managerial requirements**. A REP must have the technical and managerial resources and ability to provide continuous and reliable retail electric service to customers, in accordance with its customer contracts, PURA, commission rules, ERCOT protocols, and other applicable laws.

(1) Technical and managerial resource requirements include:

(A) Capability to comply with all applicable scheduling, operating, planning, reliability, customer registration, and settlement policies, protocols, guidelines, procedures, and other rules established by ERCOT or other applicable independent organization including any independent organization requirements for 24-hour coordination with control centers for scheduling changes, reserve implementation, curtailment orders, interruption plan implementation, and telephone number, fax number, e-mail address, and postal address where the REP's staff can be directly reached at all times.

(B) Capability to comply with the registration and certification requirements of ERCOT or other applicable independent organization and its system rules, or contracts for services with entities registered with or certified by ERCOT or other applicable independent organization.

(C) Compliance with all renewable energy portfolio standards in accordance with §25.173 of this title (relating to Goal for Renewable Energy).

(D) Principals or permanent employees in managerial positions whose combined experience in the competitive electric industry or competitive gas industry equals or exceeds 15 years. An individual that was a principal of a REP that experienced a mass transition of the REP's customers to POLR shall not be considered for purposes of satisfying this requirement, and shall not own more than 10% of a REP or directly or indirectly control a REP.

(E) At least one principal or permanent employee who has five years of experience in energy commodity risk management of a substantial energy portfolio. Alternatively, the REP may provide documentation demonstrating that the REP has entered into a contract for a term not less than two years with a provider of commodity risk management services that has been providing such services for a substantial energy portfolio for at least five years. A substantial energy portfolio means managing electricity or gas market risks with a minimum value of at least $10,000,000.

(F) Adequate staffing and employee training to meet all service level commitments.

(G) The capability and effective procedures to be the primary point of contact for retail electric customers for distribution system service in accordance with applicable commission rules, including procedures for relaying outage reports to the TDU on a 24-hour basis.

(H) A customer service plan that describes how the REP complies with the commission's customer protection and anti-discrimination rules.

(2) An applicant shall include the following in its initial application for REP certification:

(A) Prior experience of one or more of the applicant's principals or permanent employees in the competitive retail electric industry or competitive gas industry;

(B) Any complaint history, disciplinary record and compliance record during the ten years immediately preceding the filing of the application regarding: the applicant; the applicant's affiliates that provide utility-like services such as telecommunications, electric, gas, water, or cable service; the applicant's principals; and any person that merged with any of the preceding persons;

(i) The complaint history, disciplinary record, and compliance record shall include information from any federal agency including the U.S. Securities and Exchange Commission and the U.S. Commodity Futures Trading Commission; any self-regulatory organization relating to the sales of securities, financial instruments, physical or financial transactions in commodities, or other financial transactions; state public utility commissions, state attorney general offices, or other regulatory agencies in states where the applicant is doing business or has conducted business in the past including state securities boards or commissions, the Texas Secretary of State, Texas Comptroller's Office, and Office of the Texas Attorney General. Relevant information shall include the type of complaint, status of complaint, resolution of complaint, and the number of customers in each state where complaints occurred.

(ii) The applicant may request to limit the inclusion of this information if it would be unduly burdensome to provide, so long as the information provided is adequate for the commission to assess the applicant's and the applicant's principals' and affiliates' complaint history, disciplinary record, and compliance record.

(iii) The commission may also consider any complaint information on file at the commission.

(C) A summary of any history of insolvency, bankruptcy, dissolution, merger, or acquisition of the applicant or any predecessors in interest during the 60 months immediately preceding the application;

(D) A statement indicating whether the applicant or the applicant's principals are currently under investigation or have been penalized by an attorney general or any state or federal regulatory agency for violation of any deceptive trade or consumer protection laws or regulations;

(E) Disclosure of whether the applicant or applicant's principals have been convicted or found liable for fraud, theft, larceny, deceit, or violations of any securities laws, customer protection laws, or deceptive trade laws in any state;

(F) An affidavit stating that the applicant will register with or be certified by ERCOT or other applicable independent organization and will comply with the technical and managerial requirements of this subsection; or that entities with whom the applicant has a contractual relationship are registered with or certified by the independent organization and will comply with all system rules established by the independent organization;

(G) An affidavit identifying all principals, executive management, and employees, or contract employees of the applicant that exercised influence or control over a REP that experienced a mass transition of the REP's customers to POLR. If such a relationship existed, the applicant shall include in the affidavit the name of the REP that experienced a mass transition of the REP's customers to POLR and provide factual statements as to whether and, if so, how the REP that experienced a mass transition of the REP's customers to POLR settled all outstanding obligations including the return of any owed customer deposits; and

(H) Other evidence, at the discretion of the applicant, supporting the applicant's plans for meeting requirements of this subsection.

(h) **Customer protection requirements**. A REP shall comply with all applicable customer protection requirements, including disclosure requirements, marketing guidelines and anti-discrimination requirements, and the requirements of this section.

(i) **Requirements for reporting and changing certification.** To maintain a REP certificate, a REP must keep its certification information up to date, pursuant to the following requirements:

(1) A REP shall notify the commission within five working days of any change in its business address, telephone numbers, authorized contacts, or other contact information.

(2) A REP that demonstrates compliance with certification requirements of this section by submitting an affidavit shall supply information to the commission to show actual compliance with this section.

(3) A REP shall apply to amend its certification within ten working days of a material change to the information provided as the basis for the commission's approval of the certification application. A REP may seek prior approval of a material change, including a change in control, by filing the amendment application before the occurrence of the material change. The transfer of a REP certificate is a material change.

(4) For an Option 1 REP, the REP shall notify the commission within three working days of its non-compliance with subsection (f)(1)(A) or (B) of this section. The notification shall set out a plan of recourse to correct the non-compliance with subsection (f)(1)(A) or (B) of this section within 10 working days after the non-compliance has been brought to the attention of the commission. The commission staff may initiate a proceeding to address the non-compliance.

(5) For an Option 1 REP, the REP shall file a report due on March 5, or 65 days after the end of the REP or guarantor's fiscal year (annual report), and August 15, or 225 days after the end of the REP or guarantor's fiscal year (semi-annual report), of each year.

(A) The annual report shall include:

(i) Any changes in addresses, telephone numbers, authorized contacts, and other information necessary for contacting the certificate holder.

(ii) Identification of areas where the REP is providing retail electric service to customers in Texas compiled by zip code.

(iii) A list of aggregators with whom the REP has conducted business in the reporting period, and the commission registration number for each aggregator.

(iv) A sworn affidavit that the certificate holder is not in material violation of any of the requirements of its certificate.

(v) Any changes in ownership.

(vi) Any changes in management, experience, and personnel relied on for certification in each semi-annual report before the REP begins serving customers and in the first semi-annual report after the REP serves customers.

(vii) Documentation to demonstrate ongoing compliance with the financial requirements of subsection (f) of this section, including, but not limited to, calculations showing tangible net worth, financial ratios or shareholders' equity, as applicable, and the amount of customer deposits and the balance of an account in which customer deposits are held, supported by a sworn statement from an executive officer of the REP attesting to the accuracy, in all material respects, of the information provided. Any certified calculations provided as part of the annual report to demonstrate such compliance shall be as of the end of the most recent fiscal quarter. A REP may submit any relevant documentation of the type required by subsection (f)(4) of this section to demonstrate its ongoing compliance with the financial requirements of subsection (f) of this section.

(B) The semi-annual report shall include:

(i) Documentation to demonstrate ongoing compliance with the financial requirements of subsection (f) of this section, including, but not limited to, calculations showing tangible net worth, financial ratios or shareholders' equity, as applicable, and the amount of customer deposits and the balance of an account in which customer deposits are held, and shall be supported by a sworn statement from an executive officer of the REP attesting to the accuracy of the information provided. Any certified calculations provided as part of the semi-annual report to demonstrate such compliance shall be as of the end of the most recent fiscal year and most recent fiscal quarter. A REP may submit any relevant documentation of the type required by subsection (f)(4) of this section to demonstrate its ongoing compliance with the financial requirements of subsection (f) of this section.

(ii) The audited financial statements of the REP or its guarantor for the most recent completed calendar or fiscal year with accompanying footnotes and the independent auditor's report, if not previously filed.

(iii) The unaudited financial statements for the most recent six-month financial period that immediately follows the end of its most recent fiscal year. Unaudited financial statements shall include a sworn statement from an executive officer of the REP attesting to the accuracy, in all material respects, of the information provided in the unaudited financial statements. In lieu of six-month unaudited financial statements, six consecutive months of monthly financial statements may be submitted.

(C) The requirement for financial statements may be satisfied by filing a copy of or by providing an electronic link to its most recent statement that contains unaudited financials filed with any agency of the federal government, including without limitation, the Securities and Exchange Commission. A REP that is part of a structure that is consolidated for financial reporting purposes and files financial reports with a federal agency on a consolidated company basis may provide financial statements for the consolidated company to meet this requirement.

(D) REPs or guarantors with an investment-grade credit rating are not required to provide financial statements pursuant to this section.

(6) A REP shall not cease operations as a REP without prior notice of at least 45 days to the commission, to each of the REP's customers to whom the REP is providing service on the planned date of cessation of operations, and to other affected persons, including the applicable independent organization, TDUs, electric cooperatives, municipally owned utilities, generation suppliers, and providers of last resort. The REP shall file with the commission proof of refund of any monies owed to customers. Upon the effective cessation date, a REP's certificate will be suspended. A REP must demonstrate full compliance with the requirements of this section, including but not limited to, the requirement to demonstrate shareholders' equity of not less than one million dollars and its associated restrictions pursuant to subsection (f)(1)(B) of this section, in order for the commission to reinstate the certificate. The commission may revoke a suspended certificate if it determines that the REP does not meet certification requirements.

(7) If a REP files a petition in bankruptcy, is the subject of an involuntary bankruptcy proceeding, or in any other manner becomes insolvent, it shall notify the commission within three working days of this event and shall provide the commission a summary of the nature of the matter. The commission shall have the right to proceed against any financial resources that the REP relied on in obtaining its certificate, to satisfy unpaid obligations to customers or administrative penalties.

(8) A REP shall respond within three working days to any commission staff request for additional information to confirm continued compliance with this section.

(j) **Suspension and revocation.** A certificate granted pursuant to this section is subject to amendment, suspension, or revocation by the commission for a significant violation of PURA, commission rules, or rules adopted by an independent organization. A suspension of a REP certificate requires the cessation of all REP activities associated with obtaining new customers in the state of Texas. A revocation of a REP certificate requires the cessation of all REP activities in the state of Texas, pursuant to commission order. The commission may also impose an administrative penalty on a person for a significant violation of PURA, commission rules, or rules adopted by an independent organization. The commission staff or any affected person may bring a complaint seeking to amend, suspend, or revoke a REP's certificate. Significant violations include the following:

(1) Providing false or misleading information to the commission, including a failure to disclose any information required by this section;

(2) Engaging in fraudulent, unfair, misleading, deceptive, or anticompetitive practices, or unlawful discrimination;

(3) Switching, or causing to be switched, the retail electric provider for a customer without first obtaining the customer's permission;

(4) Billing an unauthorized charge, or causing an unauthorized charge to be billed, to a customer's retail electric service bill;

(5) Failure to maintain continuous and reliable electric service to customers pursuant to this section;

(6) Failure to maintain financial resources in accordance with subsection (f) of this section;

(7) Bankruptcy, insolvency, or the inability to meet financial obligations on a reasonable and timely basis;

(8) Failure to timely remit payment for invoiced charges to an independent organization;

(9) Failure to observe any applicable scheduling, operating, planning, reliability, and settlement policies, protocols, guidelines, procedures, and other rules established by the independent organization;

(10) A pattern of not responding to commission inquiries or customer complaints in a timely fashion;

(11) Suspension or revocation of a registration, certification, or license by any state or federal authority;

(12) Conviction of a felony by the certificate holder, a person controlling the certificate holder, or principal employed by the certificate holder, or any crime involving fraud, theft, or deceit related to the certificate holder's service;

(13) Not providing retail electric service to customers within 24 months of the certificate being granted by the commission;

(14) Failure to serve as a POLR if required to do so by the commission;

(15) Providing retail electric service in an area in which customer choice is in effect without obtaining a certificate under this section;

(16) Failure to timely remit payment for invoiced charges to a transmission and distribution utility pursuant to the terms of the statewide standardized tariff adopted by the commission;

(17) Erroneously imposing switch-holds or failing to remove switch-holds within the timeline described in §25.480 of this title (relating to Bill Payment and Adjustments);

(18) Failure to comply with §25.272 of this title; and

(19) Other significant violations, including the failure or a pattern of failures to meet the requirements of this section or other commission rules or orders.

§25.108. Financial Standards for Retail Electric Providers Regarding the Billing and Collection of Transition Charges.

(a) **Application.** This section applies to any retail electric provider (REP) or any other entity responsible for billing and collecting transition charges serving customers in a transmission and distribution utility (TDU) service area subject to a financing order issued by the commission under Public Utility Regulatory Act (PURA) §39.303.

(b) **Definitions.**

(1) **Financing order –** An order of the commission adopted under PURA §39.201 or §39.262 approving the issuance of transition bonds and the creation of transition charges for the recovery of qualified costs.

(2) **Indenture trustee –** An entity that administers the indenture related to transition bonds.

(3) **Servicer –** The entity responsible for carrying out obligations related to transition bonds under a servicing agreement.

(4) **Servicing agreement –** The agreement that details the obligations of the servicer related to the imposition, collection, and remittance of transition charges.

(5) **Special purpose entity (SPE)** – An entity formed by an electric utility, pursuant to a financing order, for the limited purpose of acquiring transition property, issuing transition bonds, and performing other activities relating thereto or otherwise authorized by a financing order.

(6) **Transition bonds –** Bonds, debentures, notes, certificates, of participation or of beneficial interest, or other evidences of indebtedness or ownership that are issued by an electric utility, its successors, or an assignee under a financing order, that have a term not longer than 15 years, and that are secured or payable from transition property.

(7) **Transition charges –** Nonbypassable amounts to be charged for the use or availability of electric services, approved by the commission under a financing order to recover qualified costs, that shall be collected by an electric utility, its successors, an assignee, or other collection agents as provided for in a financing order.

(c) **Applicability of REP standards.** Beginning on the date of customer choice for any retail customers, the servicer of the transition bonds will bill the transition charges for those customers to each retail customer's REP and the REP will collect transition charges from its retail customers. The standards in this section are the most stringent that can be imposed on REPs by any servicer of transition bonds. The standards relate only to the billing and collection of transition charges authorized by a financing order and do not apply to the collection of any other non-bypassable charges, or any other charges. The standards apply to all REPs other than REPs that have contracted with the transmission and distribution company to bill and collect transition charges from retail customers. REPs may contract with parties other than the transmission and distribution company to bill and collect transition charges from retail customers, but such REPs shall remain subject to the standards in this section.

(d) **REP standards.** The REP standards for transition charges are:

(1) **Rating, deposit, and related requirements.** A REP that does not have or maintain the requisite long-term, unsecured credit rating may select which alternate form of deposit, credit support, or combination thereof it will utilize, in its sole discretion. The indenture trustee shall be the beneficiary of any affiliate guarantee, surety bond or letter of credit. The provider of any affiliate guarantee, surety bond, or letter of credit must have and maintain a long-term, unsecured credit ratings of not less than "BBB-" and "Baa3" (or the equivalent) from Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's"), respectively. Each REP must:

(A) have a long-term, unsecured credit rating of not less than "BBB-" and "Baa3" (or the equivalent) from S&P and Moody's , respectively; or

(B) provide:
   (i) a deposit of two months' maximum expected transition charge collections in the form of cash,
   (ii) an affiliate guarantee, surety bond, or letter of credit providing for payment of such amount of transition-charge collections in the event that the REP defaults in its payment obligations, or
   (iii) a combination of clause (i) and (ii) of this subparagraph.

(2) **Loss of credit rating.** If the long-term, unsecured credit rating from either S&P or Moody's of a REP that did not previously provide the alternate form of deposit, credit support, or combination thereof or of any provider of an affiliate guarantee, surety bond, or letter of credit is suspended, withdrawn, or downgraded below "BBB-" or "Baa3" (or the equivalent), the REP must provide the alternate form of deposit, credit support, or combination thereof, or new forms thereof, in each case from providers with the requisite ratings, within ten business days following such suspension, withdrawal, or downgrade. A REP failing to make such provision must comply with the provisions set forth in paragraph (5) of this subsection.

(3) **Computation of deposit.** The computation of the size of a required deposit shall be agreed upon by the servicer and the REP, and reviewed during the first month of each calendar quarter to ensure that the deposit accurately reflects two months' maximum collections. If the REP provides a cash deposit, then within ten business days following such review, the REP shall remit to the indenture trustee the amount of any shortfall in such required deposit, or the servicer shall instruct the indenture trustee to remit to the REP any amount in excess of such required deposit. If the REP provides security in the form of a letter of credit or surety bond then within ten business days following such review, the REP shall submit replacement letters of credit or surety bonds in the amount determined pursuant to the review. A REP failing to so remit any such shortfall or failing to submit replacement letters of credit or surety bonds, as applicable, must comply with the provisions set forth in paragraph (5) of this subsection. REP cash deposits shall be held by the indenture trustee, as a collateral agent for the REP and the indenture trustee (in its capacity as indenture trustee) and shall be maintained in a segregated account which shall not be part of the trust estate, and invested in short-term high quality investments, as permitted by the rating agencies rating the transition bonds. Investment earnings on REP cash deposits shall be considered part of such cash deposits so long as they remain on deposit with the indenture trustee. At the instruction of the servicer, cash deposits will be remitted with investment earnings to the REP at the end of the term of the transition bonds unless otherwise utilized for the payment of the REP's obligations for transition bond payments. Once the deposit is no longer required, the servicer shall promptly (but not later than 30 calendar days) instruct the indenture trustee to remit the amounts in the segregated accounts to the REP.

(4) **Payment of transition charges.** Payments of transition charges less the charge-off allowance described in paragraph (9) of this subsection are due 35 calendar days following each billing by the servicer to the REP, without regard to whether or when the REP receives payment from its retail customers. The servicer shall accept payment by electronic funds transfer, wire transfer, and/or check. Payment will be considered received the date the electronic funds transfer or wire transfer is received by the servicer, or the date the check clears. A 5.0% penalty is to be charged on amounts received after 35 calendar days; however, a ten calendar-day grace period will be allowed before the REP is considered to be in default. A REP in default must comply with the provisions set forth in paragraph (5) of this subsection. The 5.0% penalty will be a one-time assessment measured against the current amount overdue from the REP to the servicer. The "current amount" consists of the total unpaid transition charges existing on the 36th calendar day after billing by the servicer. Any and all such penalty payments will be made to the indenture trustee to be applied against transition charge obligations. A REP shall not be obligated to pay the overdue transition charges of another REP. If a REP agrees to assume the responsibility for the payment of overdue transition charges as a condition of receiving the customers of another REP that has decided to terminate service to those customers

for any reason, the new REP shall not be assessed the 5.0% penalty upon such transition charges; however, the prior REP shall not be relieved of the previously-assessed penalties.

(5) **Remedies upon default.** After the ten calendar-day grace period (the 45th calendar day after the billing date) referred to in paragraph (4) of this subsection, the servicer shall have the option to seek recourse against any cash deposit, affiliate guarantee, surety bond, letter of credit, or combination thereof provided by the REP, and to avail itself of such legal remedies as may be appropriate to collect any remaining unpaid transition charges and associated penalties due the servicer after the application of the REP's deposit or alternate form of credit support. In addition, a REP that is in default with respect to the requirements set forth in paragraphs (2), (3), or (4) of this subsection shall select and implement one of the options listed in subparagraphs (A), (B), or (C) of this paragraph. If a REP that is in default fails to immediately select and implement one of these options or, after so selecting one of the options, fails to adequately meet its responsibilities thereunder, then the servicer shall immediately implement the option in subparagraph (A) of this paragraph. Upon re-establishment of compliance with the requirements set forth in paragraphs (2), (3), or (4) of this subsection, and the payment of all past-due amounts and associated penalties, the REP will no longer be required to comply with this paragraph.

(A) Allow the Provider of Last Resort ("POLR") or a qualified REP of the customer's choosing to immediately assume the responsibility for the billing and collection of transition charges.

(B) Immediately implement other mutually suitable and agreeable arrangements with the servicer. It is expressly understood that the servicer's ability to agree to any other arrangements will be limited by the terms of the securitization Servicing Agreement and requirements of each of the rating agencies that have rated the transition bonds necessary to avoid a suspension, withdrawal, or downgrade of the ratings on the transition bonds.

(C) Arrange that all amounts owed by retail customers for services rendered by the REP be timely billed and will immediately be paid directly into a lock-box controlled by the servicer with such amounts to be applied first to pay transition charges and other non-bypassable delivery charges before the remaining amounts are released to the REP. All costs associated with this mechanism will be borne solely by the REP.

(6) **Billing by providers of last resort.** The initial POLR appointed by the commission, or any commission-appointed successor to the POLR, must meet the minimum credit rating or deposit/credit support requirements described in paragraph (1) of this subsection in addition to any other standards that may be adopted by the commission. If the POLR defaults or is not eligible to provide such services, responsibility for billing and collection of transition charges will immediately be transferred to and assumed by the servicer until a new POLR can be named by the commission or the customer requests the services of a certified REP. If the POLR or a qualified REP assumes responsibility for billing and collecting transition charges under paragraph (5) of this subsection or servicer assumes such responsibility under this paragraph, the POLR, replacement REP, or servicer, as applicable shall bill all transition charges which have not been billed as of the date it assumes such responsibility and shall be subject to the provisions of the financing order. (For example, if a REP which bills on a calendar month basis goes into default and is replaced by the POLR on April 20, the initial transition charge bill rendered by the POLR would cover all transition charges attributable to periods since March 31, the last date for which the original REP had rendered bills). Retail customers may never be re-billed by the successor REP, the POLR, or the servicer for any amount of transition charges they have paid their REP (although future transition charges shall reflect REP and other system-wide charge-offs). Additionally, if the amount of the penalty detailed in paragraph (4) of this subsection is the sole remaining past-due amount after the 45th calendar day, the REP shall not be required to comply with paragraph (5)(A), (B) or (C) of this subsection, unless the penalty is not paid within an additional 30 calendar days.

(7) **Dispute resolution.** In the event that a REP disputes any amount of billed transition charges, the REP shall pay the disputed amount under protest according to the timelines detailed in paragraph (4)

of this subsection. The REP and servicer shall first attempt to informally resolve the dispute, but if they fail to do so within 30 calendar days, either party may file a complaint with the commission. If the REP is successful in the dispute process (informal or formal), the REP shall be entitled to interest on the disputed amount paid to the servicer at the commission-approved interest rate. Disputes about the date of receipt of transition charge payments (and penalties arising thereof) or the size of a required REP deposit will be handled in a like manner. It is expressly intended that any interest paid by the servicer on disputed amounts shall not be recovered through transition charges if it is determined that the servicer's claim to the funds is clearly unfounded. No interest shall be paid by the servicer if it is determined that the servicer has received inaccurate metering data from another entity providing competitive metering services pursuant to PURA §39.107.

(8) **Metering data.** If the servicer is providing the metering, metering data will be provided to the REP at the same time as the billing. The REP will be responsible for providing the servicer accurate metering data (including meter identification information) for all REP's customers whose meters are not read by the servicer at the time the data is provider to the independent organization (as defined in PURA §39.151(b)) under the independent organization's protocols for settlement.

(9) **Charge-off allowances.** The REP will be allowed to hold back an allowance for charge-offs in its payments to the servicer. Such charge-off rate will be recalculated each year in connection with the annual true-up procedure. In the initial year, REPs will be allowed to remit payments based on the same system-wide charge-off percentage then being used by the servicer to remit payments to the indenture trustee for the holders of transition bonds; thereafter the charge-off percentage will be calculated based upon each REP's prior year charge-off experience. On an annual basis in connection with the true-up process, the REP and the servicer will be responsible for reconciling the amounts held back with amounts actually written off as uncollectible in accordance with the terms agreed to by the REP and the servicer, provided that:

(A) The REP's right to reconciliation for charge-offs will be limited to customers whose service has been permanently terminated and whose entire accounts (*i.e.,* all amounts due the REP for its own account as well as the portion representing transition charges) have been written off.

(B) If the REP's actual charge-offs are greater than the allowance for charge-offs, the REP may collect the difference, with interest, from the date the review was completed, in 12 equal monthly installments beginning in the month that the transition charges are adjusted to reflect the new charge off percentages. The REP's recourse will be limited to a credit against future transition charge payments unless the REP and the servicer agree to alternative arrangements, but in no event will the REP have recourse to the indenture trustee, the "SPE" or the SPE's funds for such payments and the indenture trustee and SPE shall not be liable for such amounts. If the REP's actual charge-offs are less than the allowance for charge-offs, the REP shall pay the difference, with interest, from the date the review was completed, in 12 equal monthly installments beginning in the month that the transition charges are adjusted to reflect the new charge-off percentages. The interest rate on amounts due to or from the REP under this paragraph shall be the interest rate in effect pursuant to Texas Utilities Code §183.003 on the date the annual reconciliation is made. REP and servicer shall each have the unilateral right to prepay any amounts due hereunder and thus avoid continued accrual of interest.

(C) The REP shall provide ' the servicer a list of all charge-offs qualifying for reconciliation under subparagraph (A) of this paragraph, and documentation permitting servicer to verify that service to the customer has been terminated and all amounts due the REP from such customers have been written off. The information shall be provided not later than 30 days prior to the date on which the annual true-up adjustment is to be filed and shall cover the most recent 12-month period for which data is available at the time of submission. The information to be provided by the REP shall include data demonstrating that the REP has not collected any amounts the REP claimed as charge-offs in prior periods, or, if any amount previously charged-off has been collected, quantifying the revenues. The REP's rights to credits will not take effect until adjusted transition charges reflecting the REPs charge-off experience have been implemented.

(10) **Service termination.** In the event that the servicer is billing customers for transition charges, the servicer shall have the right to terminate transmission and distribution service to the end-use customer (or if the servicer is not the transmission and distribution utility to direct the transmission and distribution utility to terminate service to the end-use customer) for non-payment by the end-use customer pursuant to applicable commission rules. In the event that a REP or the POLR is billing customers for transition charges, the REP shall have the right to transfer the customer to the POLR (or to another certified REP) or to direct the transmission and distribution utility to terminate transmission and distribution service to the end-use customer for non-payment by the end-use customer pursuant to applicable commission rules. In the event that the POLR is billing customers for transition charges, the POLR shall have the right to direct the transmission and distribution utility to terminate transmission and distribution service to the end-use customer for non-payment by the end-use customer pursuant to applicable commission rules.

(11) **Precedence and modifications of REP standards in a financing order.**

(A) Compliance with financing order standards. If the REP standards in the applicable financing order are in direct conflict with the standards in this section, then the REP must comply with the REP standards stated in the financing order, instead of the standards stated in this section, unless the standards of the financing order have been modified and approved according to subparagraph (B) of this paragraph.

(B) Commission modification of standards. The commission may impose standards on REPs that are different from those in the applicable financing order but only if the commission receives prior written confirmation from each rating agency that rated the transition bonds authorized by that financing order that the proposed modifications will not cause a suspension, withdrawal, or downgrade of ratings on the transition bonds.

§25.109. Registration of Power Generation Companies and Self-Generators.

(a) **Application**.

(1) A person that owns an electric generating facility, or electric energy storage equipment or facilities to which the Public Utility Regulatory Act, Chapter 35, Subchapter E applies, in Texas and is either a power generation company (PGC), as defined in §25.5 of this title (relating to Definitions), or a qualifying facility (QF) as defined in §25.5 of this title, and generates electricity intended to be sold at wholesale, must register as a PGC.

(2) A person that owns an electric generating facility rated at one megawatt (MW) or more, but is not a PGC, must register as a self-generator. A QF that does not sell electricity or provides electricity only to the purchaser of the facility's thermal output must register as a self-generator.

(3) A person that becomes subject to this section after September 1, 2000 must register on or before the first date of generating electricity.

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

(1) Generating facility -- All generating units located at, or providing power to the electricity-consuming equipment at an entire facility or location.

(2) Nameplate rating -- The full-load continuous rating of a generator under specified conditions as designated by the manufacturer.

(3) Net dependable capability -- The maximum load in megawatts, net of station use, which a generating unit or generating station can carry under specified conditions for a given period of time, without exceeding approved limits of temperature and stress.

(4) Person -- Includes an individual, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, and a corporation, but does not include an electric cooperative.

(c) **Capacity ratings**. For purposes of this section, the capacity of generating units shall be reported as follows:

(1) Renewable resource generating units shall be rated at the nameplate rating;

(2) All other generating units having a nameplate rating of ten MW or less shall be rated at the nameplate rating; and

(3) All other generating units having a nameplate rating greater than ten MW shall be rated at the summer net dependable capability. Self-generation units that are not required to calculate net dependable capability by the reliability council in which they operate or by the independent organization for the power region in which they operate shall be rated at the nameplate rating.

(d) **Registration requirements for self-generators.** To register as a self-generator, a person shall provide all of the following information:

(1) A description of the location of the facility used to generate electricity and

(2) Any information requested on the commission-prescribed form.

(e) **Registration requirement for power generation companies**. To register as a power generation company, a person shall provide all of the following information.

(1) A description of the location of the facility used to generate electricity;

(2) A description of the types of services provided by the person that pertain to the generation of electricity;

(3) For any application filed with the Federal Energy Regulatory Commission (FERC) after the effective date of this section, copies of any information, excluding responses to interrogatories, that was filed in connection with the FERC registration, and any order issued by the FERC pursuant

thereto. Such registrations shall include, for example, determination of exempt wholesale generator (EWG) or QF status; and

(4) Any information requested on the commission-prescribed form.

(f) **Registration procedures**. The following procedures apply to the registration of PGCs and self-generators.

(1) Registration shall be made by completing the commission-prescribed form, which shall be verified by oath or affirmation and signed by an owner, partner, or officer of the registering party. Registration forms may be obtained from the Central Records division of the Public Utility Commission of Texas during normal business hours, or from the commission's Internet site. Each registering party shall file its registration form with the commission's Filing Clerk in accordance with the commission's procedural rules, Chapter 22, Subchapter E of this title (relating to Pleadings and Other Documents).

(2) The commission staff shall review the submitted form for completeness. Within 15 business days of receipt of an incomplete form, the commission staff shall notify the registering party in writing of the deficiencies in the request. The registering party shall have ten business days from the issuance of the notification to cure the deficiencies. If the deficiencies are not cured within ten business days, the staff will notify the registering party that the registration request is rejected without prejudice.

(3) The registering party may designate answers or documents that it believes to contain proprietary or confidential information. Information designated as proprietary or confidential will be treated in accordance with the standard protective order issued by the commission applicable to registration information for PGCs and self-generators.

(g) **Post-registration requirements for self-generators**. Self-generators shall report any material change during the preceding year in the information provided on the registration form by February 28 of each year.

(h) **Post-registration requirements for power generation companies**. PGCs shall report any change in the information provided on the registration form within 45 days of the change. PGCs shall comply with the reporting requirements of §25.91 of this title (relating to Generating Capacity Reports).

(i) **Suspension and revocation of power generation company registration and administrative penalty.** Pursuant to PURA §39.356, registrations of PGCs pursuant to this section are subject to suspension and revocation for significant violations of PURA or rules adopted by the commission. The commission may also impose an administrative penalty for a significant violation at its discretion. Significant violations may include the following:

(1) Failure to comply with the reliability standards and operational criteria duly established by the independent organization that is certified by the commission;

(2) For a PGC operating in the Electric Reliability Council of Texas (ERCOT), failure to observe all scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, and procedures established by the independent system operator in ERCOT;

(3) Providing false or misleading information to the commission;

(4) Engaging in fraudulent, unfair, misleading, deceptive or anti-competitive practices;

(5) A pattern of failure to meet the conditions of this section, other commission rules, regulations or orders;

(6) Suspension or revocation of a registration, certification, or license by any state or federal authority;

(7) Failure to operate within the applicable legal parameters established by PURA §39.351; and

(8) Failure to respond to commission inquiries or customer complaints in a timely fashion.

§25.111. Registration of Aggregators.

(a) **Application**. Any person, municipality, political subdivision, or political subdivision corporation that aggregates the loads of two or more electric service customers for purposes of purchasing electricity services shall register with the Public Utility Commission of Texas (commission) pursuant to this section. A single electricity customer, including a municipality or political subdivision, negotiating service in multiple locations for its own use, does not need to register with the commission.

(b) **Purpose statement.** The role of an aggregator in the restructured electric market is to be a buyer's agent for customer groups. An entity that joins customers together as a single purchasing unit and negotiates on their behalf for the purchase of electricity service in Texas is considered an aggregator and must register pursuant to this section. In contrast, an entity that sells electricity is a retail electric provider (REP) and is subject to other commission rules. This section sets out conditions for registering and operating as an aggregator, including the condition that the aggregator, a buyer's agent, may not be affiliated with a REP or other seller's agent representing the REP.

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

(1) **Aggregation** — to join two or more electricity customers into a purchasing unit to negotiate the purchase of electricity by the electricity customer as part of a voluntary association of electricity customers, provided that an electricity customer may not avoid any non-bypassable charges or fees as a result of aggregating its load.

(2) **Aggregator** — An entity is an aggregator, as opposed to a consultant, if it conducts any activity that joins two or more customers into a purchasing unit to negotiate the purchase of electricity from retail electric providers (REPs). If an entity conducts activities only in the capacity of advisor to a customer or set of customers, without contact with REPs specific to that customer or customer group, then it is a consultant that does not need to register pursuant to this section. An aggregator that provides aggregation services to Texas electricity customers must meet one of the following definitions:

(A) **Class I aggregator** — a person joining two or more customers, other than municipalities and political subdivision corporations, into a single purchasing unit to negotiate the purchase of electricity from REPs.

(B) **Class II aggregator** — a person or municipality or other political subdivision that provides aggregation services to municipalities or other political subdivisions in the manner stated below:

(i) A person authorized by two or more municipal governing bodies to join the bodies into a single purchasing unit to negotiate the purchase of electricity from REPs or a municipality aggregating under Local Government Code, Chapter 303.

(ii) A person or political subdivision corporation authorized by two or more political subdivision governing bodies to join the bodies into a single purchasing unit or multiple purchasing units to negotiate the purchase of electricity from REPs for the facilities of the aggregated political subdivisions or a person or political subdivision aggregating under Local Government Code, Chapter 303.

(3) **Person** — an individual, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, or a corporation, but not including a municipal corporation or an electric cooperative. For purposes of this section, a political subdivision or political subdivision corporation is not a person.

(4) **Political subdivision** — a county, municipality, hospital district, or any other political subdivision receiving electric service from an entity that has implemented customer choice.

(5) **Political subdivision corporation** — an entity consisting of two or more political subdivisions created to act as an agent, or otherwise, to negotiate the purchase of electricity for the use of the respective public facilities in accordance with Local Government Code §303.001.

(6) **Proprietary customer information —** any information compiled by an aggregator on a customer in the normal course of aggregating electric service that makes possible the identification of any individual customer by matching such information with the customer's name, address, account number, type or classification of service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges, billing records, or any other information that the customer has expressly requested not be disclosed. Information that is redacted or organized in such a way as to make it impossible to identify the customer to whom the information relates does not constitute propriety customer information.

(7) **Revocation** — the cessation of all aggregation business operations in the state of Texas, pursuant to commission order.

(8) **Suspension —** the cessation of all aggregation business operations in the state of Texas associated with obtaining new customers, pursuant to commission order.

(d) **Types of aggregator registrations required.**

(1) Entities seeking to aggregate electricity customers may not provide aggregation services in the state unless they have registered with the commission. Such registration may be sought after September 1, 2000.

(2) There are two types of registration available to aggregators. An entity seeking to aggregate under the terms and conditions set forth in the Public Utility Regulatory Act (PURA) §39.353 shall register as a "Class I aggregator." An entity seeking to aggregate under the terms and conditions set forth in PURA §39.354 or §39.3545, or both, shall register as a "Class II aggregator." The Class II category of registration has four subclasses, A through D. The terms of eligibility and operational requirements for each type of aggregator are specified in paragraphs (3) and (4) of this subsection. The registering party must indicate the Class and subclass, if any, under which it wishes to register. If a person is eligible and wishes to perform aggregation services under more than one class of registration, it shall obtain all applicable registrations.

(3) **Registration of Class I aggregators**. A Class I aggregator may join at least two voluntary customers into a single purchasing unit to negotiate the purchase of electricity from REPs. A Class I aggregator shall:

(A) be a person and not a REP;

(B) not be an affiliate of a REP;

(C) not include municipalities, political subdivisions, or political subdivision corporations among the customers of an aggregation;

(D) not take title to electricity, and not accept any money associated with payment or prepayment for electric service, as distinguished from aggregation services, unless it does so under contract with a REP, consistent with any rules adopted by the commission relating to customer billing as an independent billing agent for a REP;

(E) comply with the customer protection rules, disclosure requirements, and marketing guidelines of PURA and this title;

(F) comply with any other terms and conditions established by the commission to regulate reliability and integrity of aggregators.

(4) Registration of Class II aggregators. A Class II aggregator shall not be a REP or an affiliate of a REP and shall register pursuant to at least one of the following sets of eligibility and operational requirements:

(A) **Class II.A: Person that aggregates municipalities, political subdivisions, or both.** A person registered as a Class II.A aggregator pursuant to this subparagraph may join two or more authorizing municipal governing bodies into a single purchasing unit to negotiate the purchase of electricity from REPs, or it may join two or more authorizing political subdivision governing bodies, including municipal governing bodies, into single or multiple purchasing units to negotiate the purchase of electricity from REPs for the facilities of the aggregated political subdivisions. A person aggregating political subdivisions pursuant to this subparagraph may not take title to electricity. The authorizations shall be written and may specify the buyer's agent role of the aggregator to the extent desired by the political subdivision.

(B) **Class II.B: Political subdivision corporation aggregating political subdivisions.** A political subdivision corporation registered as a Class II.B aggregator pursuant to this subparagraph may join two or more authorizing political subdivision governing bodies, including municipal governing bodies, into single or multiple purchasing units to negotiate the purchase of electricity from REPs for the facilities of the aggregated political subdivisions. A political subdivision corporation aggregating political subdivisions pursuant to this subparagraph may take title to electricity.

(C) **Class II.C: Public body that aggregates its citizens.** A municipality or other political subdivision registered as a Class II.C aggregator pursuant to this subparagraph may negotiate for the purchase of electricity and energy services on behalf of each affirmatively requesting citizen of the municipality in accordance with Local Government Code §303.002, with the option to contract with a third party or another aggregator for the administration of the aggregation of the purchased services. An affirmatively requesting citizen is a resident of the political subdivision who voluntarily agrees to participate in the aggregation by a means that may be verified after the fact. If the Class II.C aggregator contracts for the administration function with a third party that is a person, other than its own employee, the person must be a registered Class II.D aggregator.

(D) **Class II.D: Administrator of citizen aggregation.** A person registered as a Class II.D aggregator pursuant to this subparagraph may administer the aggregation of electricity and energy services purchased for each requesting citizen of a municipality or other political subdivision in accordance with Local Government Code §303.002 pursuant to a contract with the municipality or political subdivision. An affirmatively requesting citizen is a resident of the political subdivision who voluntarily agrees to participate in the aggregation by a means that may be verified after the fact. A Class II.D aggregator must have verifiable authorization from the political subdivision to administer its citizen aggregation program. The authorization shall be written and may include conditions on the administrator's transactions with its affiliated REP, if any, when so specified by the political subdivision. The Class II.D registration authorizes its holder to administer a citizen aggregation program on behalf of the political subdivision but does not authorize its holder to negotiate for the purchase of electricity and energy services on behalf of the citizens of the political subdivision. An administrator of citizen aggregation must register pursuant to this subparagraph when the administrator meets the definition of "person" under this section, except when the administrator is an individual employed by the political subdivision conducting citizen aggregation pursuant to Local Government Code §303.002. A Class II.D aggregator may not take title to electricity and may not be a REP or an affiliate of a REP.

(e) **Requirements for public bodies seeking to register as Class II.B or II.C aggregators.** A municipality, other political subdivision, or political subdivision corporation seeking to register and operate as a Class II.B or Class II.C aggregator in accordance with this section shall provide the following information on a registration form approved by the commission. This subsection does not apply to registering parties who are persons, as defined in this section.

(1) The legal name of the registering party as well as any trade or commercial name(s) under which the registering party intends to operate;

(2) The registering party's Texas business address and principal place of business;
(3) The names and business addresses of the registering party's principal officers;
(4) The names of the registering party's affiliates and subsidiaries, if applicable;
(5) Telephone number of the customer service department or the name, title and telephone number of the customer service contact person;
(6) Name, physical business address, telephone number, fax number, and e-mail address for a regulatory contact person and for an agent for service of process, if a different person;
(7) The types of electricity customers that the registering party intends to aggregate; and
(8) Any other information required of public bodies on a registration form approved by the commission.

(f) **Requirements for persons seeking to register as a Class I or Class II.A or Class II.D aggregator.** A person seeking any registration under this section shall provide evidence of competency and experience in providing the scope and nature of its proposed services by providing the information listed in either paragraph (1) or (2) of this subsection on a registration form approved by the commission. This subsection does not apply to registering parties who are municipalities, other political subdivisions, or political subdivision corporations.

(1) Standard registration.

(A) The legal name(s) of the registering party. A registering party may operate under a maximum of five trade or commercial names. At the time of registration, the registering party shall provide all names to the commission and an explanation of its plan for disclosing the names to its customers;
(B) The Texas business address and principal place of business of the registering party;
(C) The name, title, business address, and phone number of each of the registering party's directors, officers, or partners;
(D) Address and telephone number for the customer or member service department or the name, title and telephone number of the customer service contact person;
(E) Name, physical business address, telephone number, fax number, and e-mail address for a Texas regulatory contact person and for an agent for service of process, if a different person;
(F) The types of electricity customers that the registering party intends to aggregate;
(G) Applicable information on file with the Texas Secretary of State, including, but not limited to, the registering party's endorsed certificate of incorporation certified by the Texas Secretary of State, a copy of the registering party's certificate of good standing, or other business registration on file with the Texas Secretary of State;
(H) Disclosure of delinquency with taxing authorities in the state of Texas;
(I) A description of prior experience, if any, of the registering party or one or more of the registering party's principals or employees in the retail electric industry or a related industry;
(J) The names of the affiliates and subsidiaries, if any, of the registering party that provide utility-related services, such as telecommunications, electric, gas, water or cable service;
(K) Disclosure of any affiliate or agency relationships and the nature of any affiliate or agency agreements with REPs or transmission and distribution utilities, and an explanation of plans for disclosure to customers and REPs with whom it does business, of its agency relationships with REPs;
(L) A list of other states, if any, in which the registering party and registering party's affiliates and subsidiaries that provide utility-related services, such as telecommunications, electric, gas, water, or cable service, currently conduct or previously conducted business;
(M) Disclosure of the registering party's known or anticipated sources of compensation for aggregation services, and an explanation of plans for disclosure to its customers of the sources of compensation for aggregation services;

(N) Disclosure of the history of bankruptcy or liquidation proceedings of the registering party or any predecessors in interest in the three calendar years immediately preceding the registration request;

(O) Disclosure of whether the registering party, a predecessor, an officer, director or principal has been convicted or found liable for fraud, theft or larceny, deceit, or violations of any customer protection or deceptive trade laws in any state;

(P) A statement indicating whether the registering party is currently under investigation, either in this state or in another state or jurisdiction for violation of any customer protection law or regulation;

(Q) The following information regarding the registering party's complaint history during the three years preceding the application:

(i) Any complaint history regarding the registering party, registering party's affiliates or subsidiaries that provide utility-related services, such as telecommunications, electric, gas, water, or cable service, the registering party's predecessors in interest, and principals with public utility commissions or public service commissions in other states where the registering party is doing business or has done business in the past. Relevant information shall include, but not be limited to, the number of complaints, the type of complaint, status of complaint, resolution of complaint and the number of customers in each state where complaints occurred. The Office of Customer Protection shall provide similar complaint information on file at the commission for review.

(ii) Any complaint history regarding the registering party, registering party's affiliates or subsidiaries that provide utility-related services, such as telecommunications, electric, gas, water or cable service, the registering party's predecessors in interest, and principals on file with the Texas Secretary of State, Texas Comptroller's Office, Office of the Texas Attorney General, and the Attorney General in other states where the registering party is doing business.

(R) For a person registering as a Class II.A aggregator, pending authorizations, if any, from public entities for the registering party to aggregate their loads.

(S) Any other information required of persons on a registration form approved by the commission.

(2) **Alternative limited registration.** A person seeking registration pursuant to this paragraph may aggregate only customers who seek to contract for 250 kilowatts or more, per customer, of peak demand electricity. Requirements for registration under this paragraph are as follows:

(A) The person shall provide the commission a signed, notarized affidavit stating that it possesses a written consent from each customer it wishes to serve, authorizing the person to provide aggregation services for that customer;

(B) The person shall complete applicable portions of the registration form other than the information prescribed in paragraph (1)(J), (K), (L), (M) and (Q) of this subsection;

(C) The person shall meet financial requirements of this section, if applicable;

(D) A person registering on the basis of this paragraph is subject to the applicable post-registration requirements of subsection (i) of this section.

(g) **Financial requirements for certain persons.** A person registering under this section who intends to take any deposits or other advance payments from electricity customers for aggregation services, as distinguished from electric services, shall demonstrate financial resources necessary to protect customers from the loss of deposits or other advance payments through fraud, business failure or other causes. Aggregation services are distinct from retail electric services. A person registered initially on the basis of not accepting customer deposits or other advance payments for aggregation services shall amend its registration with a showing to the commission that it is able to comply with the requirements of this subsection in advance of accepting deposits or other advance payments for aggregation services.

(1) **Standard financial qualifications.** The amount of required financial resources shall equal the registering person's cumulative obligations to customers arising from deposits or other advance payments for aggregation services made by customers prior to the delivery of aggregation services. A person registering under this paragraph shall disclose its methodology for calculating required financial resources on the registration form.

(A) **Financial evidence**. A aggregator may use any of the financial instruments listed below, as well as any other financial instruments approved in advance by the commission, in order to satisfy the financial requirements established by this rule.

(i) Cash or cash equivalent, including cashier's check or sight draft;

(ii) A certificate of deposit with a bank or other financial institution;

(iii) A letter of credit issued by a bank or other financial institution, irrevocable for a period of at least 15 months;

(iv) A line of credit or other loan issued by a bank or other financial institution, including a bond in a form approved by the commission, irrevocable for a period of at least 15 months;

(v) A loan issued by a subsidiary or affiliate of the applicant or a corporation holding controlling interest in the applicant, irrevocable for a period of at least 15 months;

(vi) A guaranty issued by a shareholder or principal of the applicant; a subsidiary or affiliate of the applicant or a corporation holding controlling interest in the applicant irrevocable for period of at least 15 months.

(B) **Loans or guarantees.** To the extent that it relies upon a loan or guaranty described in subparagraph (A)(v) or (vi) of this paragraph, the aggregator shall provide financial evidence sufficient to demonstrate that the lender or guarantor possesses the financial resources needed to fund the loan or guaranty.

(C) **Unencumbered resources**. All cash and other instruments listed in subparagraph (A) of this paragraph as evidence of financial resources shall be unencumbered by pledges for collateral. These financial resources shall be subject to verification and review prior to registration of the aggregator and at any time after registration in which the aggregator relies on the cash or other financial instrument to meet the requirements under this subsection. The resources available to the aggregator must be authenticated by independent, third party documentation.

(D) **Credit ratings**. To meet the requirements of this paragraph, a aggregator may rely upon either its own investment grade credit rating, or a bond, guaranty, or corporate commitment of an affiliate or another company, if the entity providing such security is also rated investment grade. The determination of such investment grade quality will be based on the ratings of either Standard & Poors (S&P) or Moody's Investor Services (Moody's). If the investment grade credit rating of either S&P or Moody's is suspended or withdrawn, the REP must provide alternative financial evidence consistent with this paragraph within ten days of the credit downgrade.

(E) **Disclosure to financial backers.** A person registering under this paragraph shall provide evidence that a copy of this rule has been provided to any party providing, either directly or indirectly, financial resources necessary to protect customers pursuant to this paragraph.

(F) **Ongoing Responsibilities.** A person registering under this paragraph is subject to the ongoing financial requirements and other applicable post-registration requirements of subsection (i) of this section.

(2) **Alternative financial qualifications for limited registration.** A person seeking registration pursuant to this paragraph is limited to aggregating only customers who seek to contract for 250 kilowatts or more, per customer, of peak demand electricity. Requirements for registration on this limited basis are as follows:

(A) The person shall provide the commission a signed, notarized affidavit indicating that it has a written consent from each customer it wishes to serve, stating that the customer is satisfied that the aggregator can provide aggregation services without establishing the cash and credit resources prescribed in paragraph (1) of this subsection.

(B) The person shall complete portions of the registration request form other than the information prescribed in paragraph (1) of this subsection;

(C) A person registering on the basis of this paragraph is subject to the applicable post-registration requirements of subsection (i) of this section.

(h) **Registration procedures.** The following procedures apply to all entities seeking to register pursuant to this section:

(1) A registration request shall be made on the form approved by the commission, verified by oath or affirmation, and signed by a registering party owner or partner, or an officer of the registering party. The form may be obtained from the Central Records division of the commission or from the commission's Internet site. Each registering party shall file its form to request registration with the commission's Filing Clerk in accordance with the commission's procedural rules, Chapter 22 of this title, Subchapter E (relating to Pleadings and Other Documents).

(2) The registering party may identify certain information or documents submitted that it believes to contain proprietary or confidential information. Registering parties may not designate the entire registration request as confidential. Information designated as proprietary or confidential will be treated in accordance with the standard protective order issued by the commission applicable to requests to register as an aggregator. If and when a public information request is received for information designated as confidential, the registering party has the burden of establishing that information filed pursuant to this rule is proprietary or confidential.

(3) An application shall be processed as follows:

(A) The registering party shall immediately inform the commission of any material change in the information provided in the registration request while the request is pending.

(B) The commission staff shall review the submitted form for completeness. Within 15 business days of receipt of an incomplete request, the commission staff shall notify the registering party in writing of the deficiencies in the request. The registering party shall have ten business days from the issuance of the notification to cure the deficiencies. If the deficiencies are not cured within ten business days, the staff will notify the registering party that the registration request is rejected without prejudice.

(C) Based upon the information provided pursuant to subsections (e), (f), and (g) of this section, the commission shall determine whether a registering party is capable of fulfilling customer protection provisions, disclosure requirements, and marketing guidelines of PURA.

(D) The commission shall determine whether to accept or reject the registration request within 60 days of the receipt of a complete application. Unacceptable registrations will be rejected without prejudice to refiling.

(i) **Post-registration requirements.**

(1) An aggregator may not refuse to provide aggregation services or otherwise discriminate in the provision of aggregation services to any customer because of race, creed, color, national origin, ancestry, sex, marital status, source or level of income, disability, or familial status; or refuse to provide aggregation services to a customer because the customer is located in an economically distressed geographic area or qualifies for low-income affordability or energy efficiency services; or otherwise unreasonably discriminate on the basis of the geographic location of a customer.

(2) An aggregator shall comply with the commission's education, disclosure, and marketing guidelines and rules, including those pertaining to customer protection and the filing of regular reports on customer complaints. An aggregator may not release proprietary customer information to any person unless the customer authorizes the release in a manner approved by the commission. An aggregator shall disclose to customers, when a customer requests aggregation services, all of its trade or

commercial names, any agency relationships with REPs, and its sources of compensation for the provision of aggregation services.

(3) An aggregator shall update any changes to business name, address, or phone number within ten business days from the date of the change.

(4) An aggregator shall notify the commission within 30 days of any material change to its registration request, or if the registrant ceases to meet any commission requirements.

(5) An aggregator may amend its registration by providing only the information relevant to the amendment on the registration form. The amendment shall be submitted pursuant to subsection (h)(1) of this section.

(6) An aggregator shall file an annual report with the commission on September 1 of each year on a form approved by the commission.

(7) An aggregator that is required to demonstrate financial qualifications specified in subsection (g)(1) of this section are subject to the following ongoing conditions:

(A) The aggregator shall maintain records on an on-going basis for any advance payments received from customers. Financial resources required under subsection (g)(1)(A) - (C) of this section, shall be maintained at levels sufficient to demonstrate that the registrant can cover all advanced payments that are outstanding at any given time.

(B) The aggregator shall file a sworn affidavit demonstrating compliance with subsection (g)(1)(A) - (D) of this section within 90 days of receiving the first payment for aggregation services before those services are rendered.

(C) Financial obligations to customers shall be payable to them within 30 business days from the date the aggregator notifies the commission that it intends to withdraw its registration or is deemed by the commission not able to meet its current customer obligations. Customer payment obligations shall be settled before registration is withdrawn.

(D) Financial resources required pursuant to subsection (g)(1) of this section shall not be reduced by the aggregator without the advance approval of the commission.

(E) The annual update required by paragraph (6) of this subsection shall include a sworn affidavit attesting to compliance with subsection (g)(1) of this section, and an explanation of the methodology for that compliance.

(F) The aggregator shall maintain records on an ongoing basis of authorizations from the public entities that have authorized it to provide aggregation services.

(8) A person that initially received its registration on the basis of not accepting payments for aggregation services, and was therefore not subject to subsection (g) of this section, shall amend its registration with a showing to the commission that it is able to comply with the requirements of subsection (g) of this section in advance of accepting payments.

(9) Persons registered pursuant to the alternative requirements for limited registration specified in subsections (f)(2) and (g)(2) of this section shall make available to the commission the written consent of individual customers, if requested.

(10) A registered aggregator that ceases to provide aggregation services may withdraw its registration by notifying the commission 30 days prior to ceasing operations and providing proof of refund of any monies owed to customers. An aggregator that withdraws its registration is not required to comply with paragraphs (1) - (9) of this subsection, following such a withdrawal.

(11) A registration shall not be transferred without prior commission approval. The transferee shall submit an application for registration in accordance with this section. The commission shall determine whether to approve the transfer within 60 days of the receipt of a complete application submitted in accordance with subsection (h) of this section.

(j) **Suspension and revocation of registration and administrative penalty.** Pursuant to PURA §39.356, registrations granted pursuant to this section are subject to suspension and revocation for significant violations of PURA or other rules adopted by the commission. At its discretion, the commission may also impose an administrative penalty for a significant violation. Significant violations include, but are not limited to, the following:

(1) providing false or misleading information to the commission;
(2) engaging in fraudulent, unfair, misleading, deceptive or anti-competitive practices;
(3) failing to maintain the minimum level of financial resources required under subsection (g)(1) of this section, if applicable;
(4) a pattern of failure to meet the conditions of this section, other commission rules, or orders;
(5) bankruptcy, insolvency, or failure to meet its financial obligations on a timely basis;
(6) suspension or revocation of a registration, certification, or license by any state or federal authority;
(7) conviction of a felony by the registrant or a principal or officer employed by the registrant, of any crime involving fraud, theft or deceit related to the registrant's aggregation service;
(8) failure to operate within the applicable legal parameters established by PURA §§39.353, 39.354, 39.3545, and Local Government Code Chapter 303;
(9) failure to respond to commission inquiries or customer complaints in a timely fashion*;*
(10) switching or causing to be switched the REP of a customer without first obtaining the customer's authorization; or
(11) billing an unauthorized charge, or causing an unauthorized charge to be billed to a customer's retail electric service bill.

(k) **Sunset of affiliate limitation**. The provisions of this section that speak to a prohibition on aggregators from affiliating with REPs cease to be effective July 1, 2003. When this occurs, the agency disclosures required in subsections (f)(1)(K) and (i)(2) of this section shall also include a requirement to disclose any affiliate relationships between the aggregator and REPs.

§25.113. Municipal Registration of Retail Electric Providers (REPs).

(a) **Applicability.** This section applies to municipalities that require retail electric providers (REPs) to register in accordance with the Public Utility Regulatory Act (PURA) §39.358 and to all REPs with a certificate granted by the commission pursuant to PURA §39.352(a) and §25.107 of this title (relating to Certification of Retail Electric Providers).

(b) **Purpose.** A municipality may require a REP to register as a condition of serving residents of the municipality, in accordance with PURA §39.358. This section establishes an optional "safe-harbor" process for municipal registration of REPs to standardize notice and filing procedures, deadlines, and registration information and fees. The "safe-harbor" registration process simplifies and provides certainty to both municipalities and REPs, thereby facilitating the development of a competitive retail electric market in Texas. If a municipality enacts a registration ordinance that is consistent with this section, the ordinance shall be deemed to comply with PURA §39.358. A municipality may exercise its authority under PURA §39.358 and adopt an ordinance that is not consistent with this section; however, such ordinance could be subject to an appeal to the commission under PURA §32.001(b).

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

(1) Resident — Any electric customer located within the municipality, except the municipality itself, regardless of customer class.

(2) Revocation — The cessation of all REP business operations within a municipality, pursuant to municipal order.

(3) Suspension — The cessation of all REP business operations within a municipality associated with obtaining new customers, pursuant to municipal order.

(d) **Non-discrimination in REP registration requirements.** A municipality shall not establish registration requirements that are different for any REP or type of REP or that impose any disadvantage or confer any preference on any REP or type of REP. However, a municipality may exclude from its registration requirement a REP that provides service only to the municipality's own electric accounts and not to any residents of the municipality.

(e) **Notice.** A municipality that enacts an ordinance adopting the standard registration process under this section shall file only the ordinance or section of ordinance, including the effective date, with the commission at least 30 days before the effective date of the ordinance. The filing shall not exceed ten pages. The filing of such a municipality's ordinance in accordance with §22.71 of this title (relating to Filing of Pleadings, Documents, and Other Materials) shall serve as notice to all REPs of the requirement to submit a registration to the municipality.

(f) **Standards for registration of REPs.** A municipality that adopts a "safe-harbor" ordinance in accordance with this section shall process a REP's registration request as follows:

(1) A REP shall register with a municipality that adopts an ordinance in accordance with this section within 30 days after the ordinance requiring registration becomes effective or 30 days after providing retail electric service to any resident of the municipality, whichever is later.

(2) A REP shall register with a municipality that adopts an ordinance in accordance with this section by completing a form approved by the commission, and signed by an owner, partner, officer, or other authorized representative of the registering REP. Forms may be submitted to a municipality by mail, facsimile, or online where online registration is available. Registration forms may be obtained from the commission's Central Records division during normal business hours, or from the commission's website.

(3) The municipality shall review the REP's submitted form for completeness, including the remittance of the registration fee. Within 15 business days of receipt of an incomplete registration, the municipality shall notify the registering REP in writing of the deficiencies in the registration. The registering REP shall have 20 business days from the issuance of the notification to cure the deficiencies. If the deficiencies are not cured within 20 business days, the municipality shall immediately send a rejection notice to the registering REP that the registration is rejected without prejudice. Absent such notification of rejection, the registration shall be deemed to have been accepted.

(4) A municipality shall not deny a REP's request for registration based upon investigations into the fitness or capability of a REP that has a current certificate from the commission.

(5) A municipality shall not require a REP to undergo a hearing before the municipality for the purposes of registration, nor require the REP to send a representative to the municipality for purposes of processing the registration form.

(g) **Information.** A municipality may require a REP to provide only the information set forth below. A REP shall provide all of the following information on the commission's prescribed form to a municipality that has adopted a "safe-harbor" ordinance under this section:

(1) The legal name(s) of the retail electric provider and all trade or commercial names;

(2) The registering REP's certificate number, as approved under **§**25.107 of this title and the docket number under which the certification was granted by the commission;

(3) The Texas business address, mailing address, and principal place of business of the registering REP. The business address provided shall be a physical address that is not a post office box;

(4) The name, physical business address, telephone number, fax number, and e-mail address for a Texas regulatory contact person and for an agent for service of process, if a different person;

(5) Toll-free telephone number for the customer service department or the name, title and telephone number of the customer service contact person;

(6) The types of electric customer classes that the REP intends to serve within the municipality; and

(7) The location of each office maintained by the registering REP within the municipal boundaries, including postal address, physical address, telephone number, hours of operation, and listing of the services available through each office.

(h) **Registration fees.** A municipality adopting the "safe-harbor" registration process may require REPs to pay a reasonable administrative fee for the purpose of registration only.

(1) A one-time registration fee of not more than $25 shall be deemed reasonable.

(2) A municipality may require a REP to pay a one-time late fee, which shall not exceed $15, only if the REP fails to register within 30 days after the ordinance requiring registration becomes effective or 30 days after providing retail electric service to any resident of the municipality, whichever is later.

(i) **Post-registration requirements and re-registration.**

(1) A REP shall notify municipalities adopting the "safe-harbor" registration within 30 days of any change in information provided in its registration. In addition, a REP shall notify a municipality within ten days if it discontinues offering service to residents of the municipality.

(2) A municipality shall not require REPs to file periodic reports regarding complaints, or any other matter, as part of the registration process.

(3) A municipality shall not require a periodic re-registration process or fee.

(4) A municipality shall not require a REP to re-register unless a REP's registration is revoked and the REP subsequently cures its defects and resumes operations. In that circumstance, the REP may register in the same manner as a new REP.

(j) **Suspension and revocation.** A municipality may suspend or revoke a REP's registration and authority to operate within the municipality only upon a commission finding that the REP has committed significant violations of PURA Chapter 39 or rules adopted under that chapter. A municipality shall not suspend or revoke the registration of the affiliated REP or provider of last resort (POLR) serving residents in the municipality. A municipality shall not take any action against a REP other than suspension or revocation of a REP's registration and authority to operate in the municipality, or imposition of a late fee in accordance with subsection (h)(2) of this section.

(1) A municipality may provide a REP with a warning prior to seeking to suspend or revoke a REP's registration.

(2) A municipality seeking to suspend or revoke a REP's registration shall provide the REP with at least 30 calendar days written notice, informing the REP that its registration and authority to operate shall be suspended or revoked. The notice shall specify the reason(s) for such suspension or revocation.

(3) A municipality may order that the REP's registration be suspended or revoked only after the notice period has expired.

(4) In its suspension order, a municipality shall specify the reasons for the suspension and provide a date certain or provide conditions that a REP must satisfy to cure the suspension. Once the suspension period has expired or the reasons for the suspension have been rectified, the suspension shall be lifted.

(5) In its revocation order, a municipality shall specify the reasons for the revocation.

(6) A REP may appeal a municipality's suspension or revocation order to the commission.

§25.121. Meter Requirements.

(a) **Use of meter.** All electricity consumed or demanded by an electric customer shall be charged for by meter measurements, except where otherwise provided for by the applicable rate schedule or contract.

(b) **Installation.** Unless otherwise authorized by the commission, each electric utility shall provide and install and shall continue to own and maintain all meters necessary for the measurement of electric energy to its customers.

(c) **Standard type.** All meters shall be of a standard type that meets industry standards. Advanced meters shall meet the standards in this section and §25.130 of this title (relating to Advanced Metering). Special meters used for investigation or experimental purposes are not required to conform to these standards.

(d) **Location of meters.**

(1) Meters and service switches in conjunction with the meter shall be installed in accordance with the latest revision of American National Standards Institute (ANSI), Incorporated, Standard C12 (American National Code for Electricity Metering), or other standards as may be prescribed by the commission, and will be readily accessible for reading, testing, and inspection, where such activities will cause minimum interference and inconvenience to the customer.

(2) Customer shall provide, without cost to the electric utility, at a suitable and easily accessible location:

(A) sufficient and proper space for installation of meters and other apparatus of electric utility;

(B) meter board;

(C) meter loop;

(D) safety service switches when required; and

(E) an adequate anchor for service drops.

(3) All meters installed after December 21, 1999, shall be located as set forth in this section, provided that, where installations are made to replace meters removed from service, this section shall not operate to require any change in meter locations which were established prior to this date, unless the electric utility finds that the old location is no longer suitable or proper, or the customer desires that the location be changed.

(4) Where the meter location on the customer's premises is changed at the request of the customer, or due to alterations on the customer's premises, the customer shall provide and have installed at his expense, all wiring and equipment necessary for relocating the meter.

(5) If provisions of this section are inconsistent with §25.214 of this title (relating to Tariff for Retail Delivery Service), the provisions of the Tariff shall control this section.

(e) **Accuracy requirements.**

(1) No meter that violates the test calibration limits as set by the American National Standards Institute, Incorporated, shall be placed in service or left in service. Whenever on installation, periodic, or other tests, a meter is found to violate these limits, it shall be adjusted or replaced.

(2) Meters shall be adjusted as closely as practicable to the condition of zero error.

(f) Notwithstanding any other commission rule**,** as a condition of receiving electric service or electric delivery service, the customer is deemed to have consented to the provision of meter data to the customer's electric utility, its retail electric provider, and the independent organization or regional transmission organization.

(g) If provisions of this subchapter are inconsistent with §25.214 of this title, the provisions of the Tariff shall control this subchapter.

§25.122. Meter Records.

Each electric utility shall keep the following records:

(1) **Meter equipment record.** Each electric utility shall keep a record of all of its meters, showing the customer's address and date of the last test. For special meters used for investigation or experimental purposes, the record shall state the purpose of the investigation or experiment.

(2) **Records of meter tests.** All meter tests shall be properly referenced to the meter record provided in paragraph (1) of this section. The record of each test made on customer's premises or on request of a customer shall show the identifying number and constants of the meter, the standard meter and other measuring devices used, the date and kind of test made, who conducted the test, the error (or percentage of accuracy) at each load tested, and sufficient data to permit verification of all calculations.

§25.123. Meter Readings.

(a) **Meter unit indication.** Each meter display shall indicate clearly the kilowatt-hours or other units of service for which a charge is made to the utilities' customer.

(b) **Reading of standard meters.** As a matter of general practice, service meters shall be read at monthly intervals, and as nearly as possible on the corresponding day of each meter reading period, but may be read at other than monthly intervals if the circumstances warrant. The electric utility shall notify the customer of any changes to the customer's meter reading cycle. This subsection does not apply to advanced metering systems.

(c) **Reading of advanced meters.** Advanced meters shall be read by the electric utility at intervals required by the Applicable Legal Authorities defined in §25.214(d)(1) of this title (relating to Tariff for Retail Delivery Service).

(d) **Customer-read program.** For meters other than advanced meters, an electric utility in an area where retail competition has not been introduced, may use a customer-read program in which customers read their own meters and report their usage monthly. Such readings shall be considered an actual meter reading by the electric utility for billing purposes. However, an electric utility shall read the meters of customers on a customer-read program at least every six months to verify the accuracy of the electric utility's records.

§25.124. Meter Testing.

(a) **Meter tests prior to installation.** No permanently installed meter shall be placed in service unless its accuracy has been established. If any permanently installed meter is removed from actual service and replaced by another meter for any purpose, it shall be properly tested and adjusted before being placed back in service unless such meter is monitored by a test program approved by the commission.

(b) **Testing of meters in service.** Meter test periods for all types of meters shall conform to the latest edition of American National Standards Institute, Incorporated, (ANSI) Standard C12 unless specified otherwise by the commission.

(c) **Meter tests on request of customer.**

(1) Each electric utility shall, upon the request of a customer, test the accuracy of the customer's meter at no charge to the customer. The test shall be made during the electric utility's normal working hours and shall be scheduled to accommodate the customer or the customer's authorized representative, if the customer desires to observe the test. The test should be made on the customer's premises, but may, at the electric utility's discretion, be made at the electric utility's test laboratory.

(2) If the meter has been tested by the electric utility, or by an authorized agency, at the customer's request, and within a period of four years the customer requests a new test, the electric utility shall make the test. However, if the subsequent test finds the meter to be within ANSI's accuracy standards, the electric utility may charge the customer a fee, which represents the cost of testing at a rate specified in the electric utility's approved tariffs.

(3) Following the completion of any requested test, the electric utility shall promptly advise the customer of the date of removal of the meter, the date of the test, the result of the test, and who made the test.

(d) **Meter testing facilities and equipment.**

(1) **Laboratory equipment.** Each electric utility furnishing metered electric service shall, either with its own facilities or a standardizing laboratory of recognized standing, provide such meter laboratory, standard meters, instruments and other equipment and facilities as may be necessary to make the meter tests required by these rules. Such equipment and facilities shall generally conform to ANSI Standard C12, unless otherwise prescribed by the commission, and shall be available at all reasonable times for inspection by the commission's authorized representatives.

(2) **Portable test equipment.** Each electric utility furnishing metered electric service shall provide portable test instruments for testing billing meters.

(3) **Reference standards.** Each electric utility shall provide or have access to suitable indicating electrical instruments as reference standards for insuring the accuracy of shop and portable instruments used for testing billing meters.

(4) **Testing of reference standards.** Reference standards of all kinds shall be submitted once each year or on a scheduled basis approved by the commission to a standardizing laboratory of recognized standing, for the purpose of test and adjustment.

(5) **Calibration of test equipment.** All shop and portable instruments used for testing billing meters shall be calibrated by comparing them with a reference standard at least every 120 days during the time such test instruments are being regularly used. Test equipment shall at all times be accompanied by a certified calibration card signed by the proper authority, giving the date when it was last certified and adjusted. Records of certifications and calibrations shall be kept on file in the office of the electric utility.

§25.125. Adjustments Due to Non-Compliant Meters and Meter Tampering in Areas Where Customer Choice Has Not Been Introduced.

(a) **Applicability.** This section applies to an electric utility in an area in which customer choice has not been introduced and shall take effect July 1, 2010.

(b) **Back-billing and meter tampering charges.** If any meter is found not to be in compliance with the accuracy standards required by §25.121(e) of this title (relating to Meter Requirements), readings for the time the meter was in service since last tested shall be corrected only as allowed below, and adjusted bills shall be rendered, except that previous readings shall not be corrected for any period in which the current customer was not the customer. The utility shall also bill the customer for any tampering, meter repair, or restoration charges due to meter tampering, if the current customer was the customer when the meter tampering began. Eligibility for an extended payment plan for back-billed amounts relating to meter tampering shall be determined under the applicable commission rules provided that, for back-billed amounts exceeding double the amount of a deposit permitted under §25.24 of this title (relating to Credit Requirements and Deposits), the utility shall offer repayment over no less than six equal monthly installments.

(c) **Calculation of charges.** The charge for any period in which the meter was not in compliance with the accuracy standard shall be based on an estimate of consumption under conditions similar to the conditions when the meter was not registering accurately, during a prior or subsequent period for that location or a similar location, to the extent such information is available.

(d) **Burden of proof.** If a customer challenges the utility's determination of meter tampering or the imposition of charges based on any such determination in a contested case proceeding before the commission, the utility bears the burden of proof that meter tampering occurred.

(e) **Additional requirements.** By April 1 of each calendar year, each utility shall file with the commission a report detailing the following for the previous calendar year concerning meter tampering:

- (1) Total number of customers for which meter tampering was determined by the utility;
- (2) The number of customers back-billed and the average of the following charges per customer:
  - (A) utility delivery and energy charges, and
  - (B) meter tampering, repair, and restoration charges; and
- (3) Total number of cases referred to law enforcement for prosecution that included photographs, a descriptive incident report, affidavit, and notification to law enforcement of the availability of physical evidence in the case.

§25.126. Adjustments Due to Non-Compliant Meters and Meter Tampering in Areas Where Customer Choice Has Been Introduced.

(a) **Applicability.** This section applies to a transmission and distribution utility (TDU) and a retail electric provider (REP) in an area in which customer choice is available. The implementation of this section shall take effect on July 1, 2010. This section does not limit a TDU's or REP's right to seek redress for meter tampering through civil and criminal proceedings.

(b) **Back-billing and meter tampering charges.**

(1) If any meter is found to be non-compliant with the accuracy standards required by §25.121(e) of this title (relating to Meter Requirements), or if the TDU has provided incorrect consumption or billing data to the REP, then consumption or billing data shall be corrected, and adjusted bills shall be rendered. The TDU shall not back-bill for any period in which the current customer was not the customer of record, or the current REP was not the REP of record. The TDU shall not assess any meter tampering fees, meter repair charges, or restoration charges due to meter tampering, if the current customer was not the customer of record when the meter tampering began, or if the current REP was not the REP of record when the meter tampering began.

(2) Back-billing under this subsection shall not exceed a period of:

(A) three months, if the TDU discovers a non-compliant meter or other equipment that has not been affected by meter tampering and the back-billing would result in additional electricity charges to the customer; or

(B) six months, if the TDU discovers a non-compliant meter that has been affected by meter tampering and the back-billing would result in additional charges or fees to the customer.

(3) The back-billing shall not be limited if the TDU discovers a non-compliant meter that has not been affected by meter tampering or has provided incorrect meter readings that are unrelated to meter tampering and the back-billing would result in a credit to the customer.

(4) In instances where the TDU finds it appropriate, the TDU may assess charges for services received by the customer prior to the six months back-billed to the REP, and the charges assessed beyond six months shall be sent to the end-use customer directly by the TDU. Charges assessed by the TDU pursuant to this paragraph may extend to periods in which the current REP of record was not the REP of record. Energy charges shall be determined using the ERCOT-wide bus average hub price as calculated by the independent system operator for the applicable time periods. The utility shall notify the current REP of record of the charges assessed to the customer beyond six months. The TDU shall pay the current REP of record 50% of the energy charges collected for the period of time in which that REP was the REP of record. The TDU shall provide the energy charges to the REP pursuant to a method agreed to by the REP and the TDU.

(c) **Calculation of charges.** The charge for any period in which the meter was not in compliance with the accuracy standard shall be based on an estimate using the standards for calculation as stated in the Tariff for Retail Delivery Service, Section 4.8.1.4, adopted pursuant to §25.214 of this title (relating to Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities).

(d) **TDU responsibilities concerning metering accuracy.** A TDU shall undertake all reasonable efforts to minimize losses associated with inaccurate meters and meter tampering, including the prompt detection and investigation of circumstances in which a meter is not accurately recording and reporting consumption. The TDU shall also take the steps necessary to deter meter tampering and to mitigate the adverse impacts of inaccurate meters on the metering and billing of electricity consumption.

(1) Once meter tampering is determined to have taken place, the TDU shall restore normal meter registration and reading within three business days. If the tampering involves a bypass of the

meter, and the TDU cannot eliminate the bypass, the TDU shall, within this period, disconnect service to the premises.

(2) Following disconnection, the TDU shall provide written notice of disconnection to the customer of record and notice to the REP using a standard market process.

(3) The TDU shall, concurrent with the back-billing, supply the REP with the revised estimated meter read resulting from consumption at the premises that the TDU has determined was not previously billed as a result of the meter tampering. The electronic transaction transmitting the estimated meter read to the REP shall clearly denote that the meter read is an estimate and shall state the reason for the estimation.

(4) All applicable meter repair and restoration charges shall be sent in a single transaction by the TDU and shall not be spread over several months. The TDU shall send corresponding back-billing transactions concurrently with the transaction for meter repair and restoration charges.

(5) The TDU shall investigate, and remedy if necessary, all instances of meter tampering reported under this section within ten business days from the date the tampering was reported to the TDU.

(6) The TDU may not invoice the current REP for any back-billed TDU charges related to meter tampering or for any meter repair and restoration charges, until the TDU has placed a switch-hold on the affected ESI pursuant to subsection (g) of this section and collected and prepared the following information in support of a determination of meter tampering. The TDU shall make the information specified in this paragraph electronically and readily available to the REP of record through a secure method, without requiring the REP of record to first request the information. The TDU shall also provide the affected customer this information within five business days of the customer's request. The TDU shall provide reasonable and timely access to the physical items specified in subparagraph (D) of this paragraph to any requesting REP of record or customer.

(A) Photographs of the premises including a general photograph of the residence/business (showing address number if available), a wide shot photograph of the meter against the wall or where attached to the premises, and close-ups of the meter and/or diversion evidence (prior to removing the meter cover if the tampering is obvious and after removing the meter cover if the damage is inside the meter), and any other relevant evidence that can be photographed;

(B) A detailed description of the detection and investigation methodology employed by the TDU;

(C) Documentation of the methodology or rationale used by the TDU to determine the date or approximate date upon which the meter ceased accurately registering consumption at the premises and the detailed calculation and methodology for estimating consumption subject to back-billing, and the methodology used to calculate the back-billing;

(D) The affected meter and other metering equipment that the TDU may need to remove from the premises because the tampering involved an unauthorized alteration, manipulation, change or modification of that equipment, and any available object used for meter tampering;

(E) Any other reliable and credible information that supports its conclusion that the meter was tampered with, while maintaining confidentiality of anonymous tips provided to the TDU; and

(F) A sworn affidavit from an employee or other representative of the TDU attesting to the veracity of the information.

(7) The information specified in paragraph (6) of this subsection shall be retained by the TDU for 24 months from the date the TDU invoices the REP pursuant to paragraph (6) of this subsection and, if a legal proceeding is initiated during those 24 months, the information shall be retained by the TDU until the final resolution of that proceeding, or 24 months, whichever is later.

(e) **Notification of meter tampering.** The TDU shall notify the REP within one business day, upon a determination that meter tampering has occurred through a standard market process. The TDU shall also notify the customer within two business days of the determination of meter tampering.

(1) The notice to the customer shall be either provided to the customer in the form of a door hanger, or mailed to the premises address assigned to the ESI ID or an address provided by the REP if there is no valid postal premises address assigned to the ESI ID.

(2) The notice shall include the following information in the same format as follows:

[TDU Letterhead]

Date: ________________

Address: ___________________________________

ESI-ID: ____________________________________

NOTICE OF METER TAMPERING

We have identified electric meter tampering, or theft of electric service at this location.

You may be billed for any applicable fees relating to repairing or replacing the electric meter and other facilities, and for electricity usage not previously billed as a result of the tampering or theft. A bill for these charges will be issued by your retail electric provider (REP). If the meter tampering occurred prior to the time you became the customer of record at this location, you may be billed for any of your electricity usage that was previously unbilled. If the meter tampering began after you became customer of record at this location and your current REP was providing your electric service at that time, you may also be billed meter repair and restoration charges. Your REP may also authorize disconnection of service for nonpayment. You will not be able to switch your service to another REP until you have satisfied your obligation to pay these charges.

(f) **Burden of Proof.** If a retail customer challenges the TDU's determination of meter tampering, or the imposition of charges based on any such determination, in a contested case proceeding before the commission, the TDU shall bear the burden of proof that meter tampering occurred.

(g) **Switch-hold and disconnection of service.** Upon determination by the TDU that tampering has occurred at a premises, the TDU shall on the same day place a switch-hold on the ESI ID, which shall prevent a switch or move-in transaction from being completed for the ESI ID. If the REP exercises its right to disconnect service for non-payment pursuant to §25.483 of this title (relating to Disconnection of Service), the switch-hold shall continue to remain in place. The switch-hold shall remain in effect until the REP of record notifies the TDU to remove the switch-hold because the customer has satisfied its payment obligations for back-billings and meter repair charges due to tampering, or until such time as removal of the switch-hold is otherwise authorized by this section. The TDU shall create and maintain a secure list of ESI IDs with switch-holds that REPs may access. The list shall not include any customer information other than the ESI ID and date the switch-hold was placed. The list shall be updated daily, and made available through a secure means by the TDU. The TDU may provide this list in a secure format through the web portal developed as part of its AMS deployment.

(1) The REP via a standard market process shall submit a request to remove the switch-hold once satisfactory payment is received from the retail customer for the back-billings and meter repair and restoration charges.

(2) For a customer receiving service under §25.498 of this title (relating to Retail Electric Service Using a Customer Prepayment Device or System), a TDU shall disconnect service within one day of its receipt of the REP's request for disconnection if the TDU has determined that tampering with the customer's meter has occurred.

(3) At the time of a mass transition, the TDU shall remove the switch-hold for any ESI ID that is transitioned to a provider of last resort (POLR). No later than the business day following the completion of the last mass transition switch, the TDU shall provide all POLR providers a list of ESI IDs previously subject to a switch-hold.

(4) When the REP of record issues a move-out request for an ESI ID under a switch-hold, the REP of record's relationship with the ESI ID is terminated and the switch-hold shall be removed.

(h) **Move-ins with a valid switch-hold.**

(1) If a retail applicant for electric service selects a REP and the selected REP submits a move-in transaction for an ESI ID that has an existing switch-hold as defined in subsection (g) of this section due to meter tampering, the TDU shall notify the selected REP that the move-in transaction is rejected via a standard market process. If the selected REP determines the applicant's premise has an existing switch-hold, the selected REP may request removal of the switch-hold prior to submitting a move-in transaction.

(2) The selected REP shall use best efforts to promptly determine whether the applicant for electric service is a new occupant not associated with the customer for which the switch-hold was imposed and, if so, obtain adequate documentation that the move-in request is legitimate. Adequate documentation shall include a copy of a signed lease, an affidavit of a landlord, closing documents, a certificate of occupancy, a utility bill dated within the past two months from a different premise, or other comparable documentation in the name of the retail applicant for electric service, and shall include a signed statement from the applicant stating that the applicant is a new occupant of the premises and is not associated with the preceding occupant.

(3) Upon receipt of such information from the applicant, the selected REP shall ensure that the applicant's financial information, driver's license number, and social security number and federal tax ID number are protected from improper release. Another REP or a TDU that receives such information from the selected REP shall also protect such information from release.

(4) The selected REP shall initiate the use of ERCOT's MarkeTrak issue process to request removal of the switch-hold and provide the supporting documentation to the TDU. This request and supporting documentation shall be subsequently provided to the current REP of record through the MarkeTrak process.

(5) The current REP of record may submit other information in response to the supporting documentation submitted by the selected REP, using the MarkeTrak process. This additional information shall be made available to the TDU and the selected REP through the MarkeTrak process. Within four business hours of receiving the request to remove the switch-hold and supporting documentation, the TDU shall determine whether the switch-hold should be removed by confirming the documentation provided under subsection (h)(2) of this section is adequate. In making this decision, the TDU shall take into consideration any additional information submitted by the current REP of record. If the TDU determines the documentation is inadequate, the selected REP and the current REP of record shall be immediately notified through the MarkeTrak process that the request to remove the switch-hold is rejected, and the switch-hold shall remain in effect pursuant to subsection (g) of this section. If the TDU concludes that the documentation is adequate, it shall immediately grant the request to remove the switch-hold and both the selected REP and current REP record shall be immediately notified of the removal through the MarkeTrak

process. After being notified of the removal of the switch-hold, the selected REP shall resubmit the move-in transaction to initiate the move-in request.

(6) A TX SET transaction or process developed specifically for the purpose of addressing the treatment of switch-holds in the context of move-in transactions shall be used as a substitute for the equivalent process described in this subsection once that TX SET transaction becomes available. The Electric Reliability Council of Texas (ERCOT) shall develop this TX SET transaction process as soon as possible.

(7) For a move-in transaction indicating that the ESI ID is subject to a continuous service agreement, the TDU shall remove any switch-hold on that ESI ID and complete the move-in.

(i) **Additional requirements.**

(1) By April 1 of each calendar year, each TDU shall file with the commission a report detailing the following for the previous calendar year concerning meter tampering:

(A) Total number of customers for which meter tampering was determined by the TDU;

(B) The number of customers back-billed and the average of the following charges per customer:

(i) utility delivery charges; and

(ii) meter repair, and restoration charges.

(C) Total number of cases referred to law enforcement for prosecution that included photographs, a descriptive incident report, affidavit, and notification to law enforcement of the availability of physical evidence in the case;

(D) Total number of cases prosecuted;

(E) Switch-hold statistics, including the number of ESI IDs for which a switch-hold was placed, the number of ESI IDs placed under a switch hold for three months, six months, one year, or longer; and

(F) The number of premises for which a TDU assessed charges directly to the customer pursuant to subsection (b)(4) of this section.

(2) The utility shall maintain adequate staff responsible for monitoring suspicious activity related to meter tampering in its service territory. The utility shall establish a process for REPs and customers to report meter tampering. The TDU shall also include a customer hotline telephone number or email address on its website, prominently displayed on its front page for electric service.

(3) The utility shall maintain a record of meter tampering investigations. The record shall include a timeline by ESI ID, starting with the date information is reported by a REP, landlord, TDU employee or other individual on meter tampering, the date the TDU completed the investigation, and the date the TDU issued the back-billing to the REP. The utility shall make this information available to the commission upon request.

(4) The utility shall engage in a customer information campaign to educate customers on the safety hazards associated with electricity theft, diversion, and meter tampering.

(j) **Proprietary Customer Information.** The prohibition against the release of proprietary customer information in §25.472 of this title (relating to Privacy of Customer Information) does not prohibit the release of customer proprietary information to the registration agent, a REP, a POLR provider, or a TDU when the information is necessary to complete a market transaction described in this section. Customer proprietary information provided in accordance with this section shall be treated as confidential, shall be securely destroyed by the current REP of record after 24 months, and shall be used only for the purposes of evaluating whether to lift a switch-hold and cannot be used for any other purpose, including but not limited to marketing or sales efforts by the current REP.

§25.127. Generating Station Meters, Instruments, and Records.

(a) **Generating station meters.** Instruments and meters shall be installed and maintained at each generating station as may be necessary to obtain a record of the output as required, and to show the character of service being rendered from the generating station.

(b) **Record of station output and purchases of energy.** Each electric utility shall keep a daily record of the load and a monthly record of the output of its plants.

§25.128. Interconnection Meters and Circuit Breakers.

(a) Each electric utility purchasing electric energy shall ensure that all instruments and meters are maintained as may be necessary to obtain full information as to purchases, unless this information is metered and furnished by the electric utility supplying the energy.

(b) **Record of automatic circuit breaker operations.** Each electric utility shall keep monthly records of the number and cause, if known, of the operations of every automatic circuit breaker in service on its transmission and distribution systems.

§25.129. Pulse Metering.

(a) **Purpose.** The purpose of this section is to facilitate customer access to electrical pulse (pulse) as defined in §25.341 of this title (relating to Definitions) under terms and conditions specified in subsection (c) of this section.

(b) **Application**. This section applies to transmission and distribution (T&D) utilities, except river authorities. Each T&D utility shall provide access to pulse from the revenue meter and shall provide pulse access in accordance with an Agreement and Terms and Conditions for Pulse Metering Equipment Installation (PMEI agreement), as approved by the commission for all requesting customers.

(c) **Commission approved pulse metering agreement.** Each T&D utility shall provide pulse metering equipment pursuant to the PMEI agreement as approved by the commission.

(d) **Filing requirements for tariffs.** No later than 15 days after the effective date of this section, each T&D utility that does not have a tariff that contains a schedule detailing the charges for providing pulse metering equipment, installation and replacement and, if offered, equipment maintenance shall file a tariff or tariffs containing a schedule detailing the charges for providing pulse metering equipment, installation, and replacement and, if offered, equipment maintenance. The tariff shall conform to the commission rules and the PMEI agreement. Concurrent with the tariff filing in this section, each T&D utility that does not have an approved tariff that contains a schedule detailing the charges for providing pulse metering equipment, installation and, if offered, equipment maintenance shall submit all supporting data for the charges. No later than 15 days after the effective date of this section, each utility shall submit the PMEI agreement as described in subsection (c) of this section and approved by the commission.

§25.130. Advanced Metering.

(a) **Purpose.** The purposes of this section are to authorize electric utilities to assess a nonbypassable surcharge to use to recover costs incurred for deploying advanced metering systems that are consistent with this section; increase the reliability of the regional electrical network; encourage dynamic pricing and demand response; improve the deployment and operation of generation, transmission and distribution assets, and provide more choices for electric customers.

(b) **Applicability**. This section is applicable to all electric utilities, including transmission and distribution utilities, other than an electric utility that, pursuant to Public Utility Regulatory Act (PURA) §39.452(d)(1), is not subject to PURA §39.107; and to the Electric Reliability Council of Texas (ERCOT).

(c) **Definitions**.

(1) Advanced meter -- Any new or appropriately retrofitted meter that functions as part of an advanced metering system and that has the features specified in this section.

(2) Advanced Metering System (AMS) -- A system, including advanced meters and the associated hardware, software, and communications systems, including meter information networks, that collects time-differentiated energy usage and performs the functions and has the features specified in this section.

(3) Deployment Plan -- An electric utility's plan for deploying advanced meters in accordance with this section and either filed with the commission as part of the Notice of Deployment or approved by the commission following a Request for Approval of Deployment.

(4) Dynamic Pricing -- Retail pricing for electricity consumed that varies during different times of the day.

(5) Non-standard advanced meter -- A meter that contains features and functions in addition to the AMS features in the deployment plan approved by the commission.

(d) **Deployment and use of advanced meters.**

(1) Deployment and use of AMS by an electric utility is voluntary unless otherwise ordered by the commission. However, deployment and use of an AMS for which an electric utility seeks a surcharge for cost recovery shall be consistent with this section, except to the extent that the electric utility has obtained a waiver from the commission.

(2) Six months prior to initiating deployment of an AMS or as soon as practicable after the effective date of this section, whichever is later, an electric utility that intends to deploy an AMS shall file a Statement of AMS Functionality, and either a Notice of Deployment or a Request for Approval of Deployment. An electric utility may request a surcharge pursuant to subsection (k) of this section in combination with a Notice of Deployment or a Request for Approval of Deployment, or separately. A proceeding that includes a request to establish or amend a surcharge shall be a ratemaking proceeding and a proceeding involving only a Request for Approval of Deployment shall not be a ratemaking proceeding.

(3) The Statement of AMS Functionality shall:

(A) state whether the AMS meets the requirements specified in subsection (g) of this section and what additional features, if any, it will perform;

(B) describe any variances between technologies and meter functions within its service territory; and

(C) state whether the electric utility intends to seek a waiver of any provision of this section in its request for surcharge.

(4) A Deployment Plan shall contain the following information:

(A) Type of meter technology;

(B) Type and description of communications equipment in the AMS;

(C) Systems that will be developed during the deployment period;
(D) A timeline for the web portal development;
(E) A deployment schedule by specific area (geographic information);
(F) When postings of monthly status reports on the electric utility's website will commence; and
(G) A schedule for deployment of web portal functionalities.

(5) An electric utility shall file with the Deployment Plan, testimony and other supporting information, including estimated costs for all AMS components, estimated net operating cost savings expected in connection with implementing the Deployment Plan, and the contracts for equipment and services associated with the Deployment Plan, that prove the reasonableness of the plan.

(6) Competitively sensitive information contained in the Deployment Plan and monthly progress reports may be filed confidentially. An electric utility's Deployment Plan shall be maintained and made available for review on the electric utility's website for REP access. Competitively sensitive information contained in the Deployment Plan shall be maintained and made available at the electric utility's offices in Austin. Any REP that wishes to review competitively sensitive information contained in the electric utility's deployment plan available at its Austin office, may do so during normal business hours upon reasonable advanced notice to the electric utility and after executing a non-disclosure agreement with the electric utility.

(7) If the request for approval of a Deployment Plan contains the information described in paragraph (4) of this subsection and the AMS features described in subsection (g)(1) of this section, then the commission shall approve or disapprove the Deployment Plan within 150 days, but this deadline may be extended by the commission for good cause.

(8) An electric utility's treatment of AMS, including technology, functionalities, services, deployment, operations, maintenance, and cost recovery shall not be unreasonably discriminatory, prejudicial, preferential, or anticompetitive.

(9) Each electric utility shall provide progress reports on a monthly basis and status reports every six months following the filing of its Deployment Plan with the commission until deployment is complete. Upon filing of such reports, the electric utility shall notify all certified REPs of the filing through standard market notice procedures. A monthly progress report shall be filed within 15 days of the end of the month to which it applies, and shall include the following information:
(A) the number of advanced meters installed, listed by ESI ID. Additional information if available may also be listed, such as county, city, zip code, feeder numbers, and any other easily discernable geographic identification available to the electric utility;
(B) significant delays or deviation from the Deployment Plan and the reasons for the delay or deviation;
(C) a description of significant problems the electric utility has experienced with an AMS, with an explanation of how the problems are being addressed;
(D) the number of advanced meters that have been replaced as a result of problems with the AMS; and
(E) the status of deployment of features identified in the Deployment Plan and any changes in deployment of these features.

(10) If an electric utility has received approval of its Deployment Plan from the commission, the electric utility shall obtain commission approval before making any changes to its AMS that would affect a REP's ability to utilize any of the AMS features identified in the electric utility's Deployment Plan by filing a request for amendment to its Deployment Plan. In addition, an electric utility may request commission approval for other changes in its approved Deployment Plan. The commission shall act upon the request for an amendment to the Deployment Plan within 45 days of submission of the request, unless good cause exists for additional time. If an electric utility filed a Notice of Deployment, the electric utility shall file an amendment to its Notice of Deployment at least 45 days before making any changes to its AMS that would affect a REP's ability to utilize any of the AMS

features identified in the electric utility's Notice of Deployment. This paragraph does not in any way preclude the electric utility from conducting its normal operations and maintenance with respect to the electric utility's transmission and distribution system and metering systems.

(11) During and following deployment, any outage related to normal operations and maintenance that affects a REP's ability to obtain information with the system shall be communicated to the REP through the outage/restoration notice process according to Applicable Legal Authorities, as defined in §25.214(d)(1) of this title (relating to Tariff for Retail Delivery Service).

(12) The electric utility shall not provide any advanced metering equipment or service that is deemed a competitive energy service under §25.343 of this title (relating to Competitive Energy Services). Any functionality of the AMS that is a required function under this section or that is included in an approved Deployment Plan does not constitute a competitive energy service under §25.343 of this title.

(13) An electric utility's deployment and provision of AMS services and features, including but not limited to the features required in subsection (g) of this section, are subject to the limitation of liability provisions found in the electric utility's tariff.

(e) **Technology requirements.** Except for pilot programs, an electric utility shall not deploy AMS technology that has not been successfully installed previously with at least 500 advanced meters in North America, Australia, Japan, or Western Europe.

(f) **Pilot programs.** An electric utility may deploy AMS with up to 10,000 meters that do not meet the requirements of subsection (g) of this section in a pilot program, to gather additional information on metering technologies, pricing, and management techniques, for studies, evaluations, and other reasons. A pilot program may be used to satisfy the requirement in subsection (e) of this section. An electric utility is not required to obtain commission approval for a pilot program. Notice of the pilot program and opportunity to participate shall be sent by the electric utility to all REPs.

(g) **AMS features.**

(1) An AMS shall provide or support the following minimum system features in order to obtain cost recovery through a surcharge pursuant to subsection (k) of this section:

(A) automated or remote meter reading;

(B) two-way communications;

(C) remote disconnection and reconnection capability for meters rated at or below 200 amps, provided that an electric utility shall be considered in compliance with this provision if it makes this function available in all advanced meters installed after the effective date of this rule, and the following meters shall also be considered in compliance with this provision: those advanced meters that were ordered prior to the effective date of this rule, not to exceed 65,000 meters over the number of meters received or ordered as of May 10, 2007, and are provisioned with all the features enumerated in this paragraph except remote disconnect and reconnect capability, if those advanced meters are installed by December 31, 2007, and the number of advanced meters installed with all the features enumerated in this paragraph except remote disconnect and reconnect capability does not exceed 18% of the total number of advanced meters installed by the electric utility pursuant to a Deployment Plan.

(D) the capability to time-stamp meter data sent to the independent organization or regional transmission organization for purposes of wholesale settlement, consistent with time tolerance standards adopted by the independent organization or regional transmission organization;

(E) the capability to provide direct, real-time access to customer usage data to the customer and the customer's REP, provided that:

(i) hourly data shall be transmitted to the electric utility's web portal on a day-after basis.

(ii) the commission staff using a stakeholder process, as soon as practicable shall determine, subject to commission approval, when and how 15-minute IDR data shall be made available on the electric utility's web portal.

(F) means by which the REP can provide price signals to the customer;

(G) the capability to provide 15-minute or shorter interval data to REPs, customers, and the independent organization or regional transmission organization, on a daily basis, consistent with data availability, transfer and security standards adopted by the independent organization or regional transmission organization;

(H) on-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as in American National Standards Institute (ANSI) C12.19 tables;

(I) open standards and protocols that comply with nationally recognized non-proprietary standards such as ANSI C12.22, including future revisions thereto;

(J) capability to communicate with devices inside the premises, including, but not limited to, usage monitoring devices, load control devices, and prepayment systems through a home area network (HAN), based on open standards and protocols that comply with nationally recognized non-proprietary standards such as ZigBee, Home-Plug, or the equivalent; and

(K) the ability to upgrade these minimum capabilities as technology advances and, in the electric utility's determination, become economically feasible.

(2) An electric utility shall offer, as discretionary services in its tariff, installation of non-standard meters and advanced meter features.

(A) A REP may require the electric utility to provide non-standard advanced meters, additional metering technology, or advanced meter features not specifically offered in the electric utility's tariff, that are technically feasible, generally available in the market, and compatible with the electric utility's AMS;

(B) The REP shall pay the reasonable differential cost for the non-standard advanced meters or features.

(C) Upon request by a REP, an electric utility shall expeditiously provide a report to the REP that includes an evaluation of the cost and a schedule for providing the nonstandard advanced meters or advanced meter features of interest to the REP. The REP shall pay a reasonable discretionary services fee for this report. This discretionary services fee shall be included in the electric utility's tariff.

(D) If an electric utility agrees to deploy non-standard advanced meters or advanced meter features not addressed in its tariff at the request of the REP, the electric utility shall expeditiously apply to amend its tariff to specifically include the non-standard advanced meters or meter features that it agreed to deploy.

(3) An electric utility may petition the commission for a waiver of the requirements of paragraph (1) of this subsection for portions of its service area where it would be uneconomic or technically infeasible to implement particular system features. A waiver may also be granted for an AMS that exceeds or is an adequate substitute for the requirements in paragraph (1) of this subsection. The electric utility shall provide all relevant studies and cost-benefit analysis and other evidence supporting its waiver request and shall bear the burden of proof in its waiver request. An electric utility that has received a waiver shall explain in the report required by subsection (d)(7) of this section, technology changes and changes in the cost of deployment or savings to the electric utility that would make it economic or technically feasible to offer the system features in the affected portions of its service area. Any waiver granted by the commission shall extend only to those costs and expenses for which the waiver is granted in any proceeding in which the electric utility seeks to recover its costs through the surcharge mechanism addressed in subsection (k) of this section.

(4) In areas where there is not a commission-approved independent regional transmission organization, standards referred to in this section for time tolerance and data transfer and security may be approved by a regional transmission organization approved by the Federal Energy Regulatory Commission or, if there is no approved regional transmission organization, by the commission.

(5) Once an electric utility has deployed its advanced meters, it may add or enhance features provided by AMS, as technology evolves and in accordance with Applicable Legal Authorities. The electric utility shall notify the commission and REPs of any such additions or enhancements at least three months in advance of deployment, with a description of the features, the deployment and notification plan, and the cost of such additions or enhancements, and shall follow the monthly progress report process described in subsection (d)(8) of this section until the enhancement process is complete.

(6) Beginning January 1, 2008, or as soon as such meters are commercially available from the electric utility's current vendor, whichever is earlier, an electric utility shall replace, at no cost to the customer, an advanced meter with all the features enumerated in paragraph (1) of this subsection except remote disconnect and reconnect capability, if: the meter has reached the end of its useful life; the meter has been removed for repair; the premises at which the meter is located has experienced an unusually high number of disconnections and reconnections; or the REP has informed the electric utility that its customer has agreed to utilize a prepaid service and the REP has requested a meter with remote disconnection and reconnection capability. If by January 1, 2009, requests by REPs for replacement of advanced meters with all the features enumerated in paragraph (1) of this subsection except remote disconnect and reconnect capability exceed 20% of those meters, then the electric utility shall replace all of those meters as soon as possible with meters that meet the requirements of paragraph (1) of this subsection and have remote disconnect and reconnect capability.

(h) **Settlement.** It is the objective of this rule that ERCOT shall be able to use 15-minute meter information from advanced metering systems for wholesale settlement, not later than January 31, 2010.

(i) **Tariff.** All non-standard, discretionary AMS features offered by the electric utility shall be described in the electric utility's tariff.

(j) **Access to meter data.**

(1) An electric utility shall provide a customer, the customer's REP, and other entities authorized by the customer read-only access to the customer's advanced meter data, including meter data used to calculate charges for service, historical load data, and any other proprietary customer information. The access shall be convenient and secure, and the data shall be made available no later than the day after it was created.

(2) The requirement to provide access to the data begins when the electric utility has installed 2,000 advanced meters for residential and non-residential customers. If an electric utility has already installed 2,000 advanced meters by the effective date of this section, the electric utility shall provide access to the data in the timeframe approved by the commission in either the Deployment Plan or request for surcharge proceeding. If only a Notice of Deployment has been filed, access to the data shall begin no later than six months from the filing of the Notice of Deployment with the commission.

(3) An electric utility shall use industry standards and methods for providing secure customer and REP access to the meter data. The electric utility shall have an independent security audit of the mechanism for customer and REP access to meter data conducted within one year of initiating such access and promptly report the results to the commission.

(4) The independent organization, regional transmission organization, or regional reliability entity shall have access to information that is required for wholesale settlement, load profiling, load research, and reliability purposes.

(5) A customer may authorize its data to be available to an entity other than its REP.

(k) **Cost recovery for deployment of AMS.**

(1) **Recovery Method.** The commission shall establish a nonbypassable surcharge for an electric utility to recover reasonable and necessary costs incurred in deploying AMS to residential customers and nonresidential customers other than those required by the independent system operator to have an interval data recorder meter. The surcharge shall not be established until after a detailed Deployment Plan is filed pursuant to subsection (d) of this section. In addition, the surcharge shall not ultimately recover more than the AMS costs that are spent, reasonable and necessary, and fully allocated, but may include estimated costs that shall be reconciled pursuant to paragraph (6) of this subsection. As indicated by the definition of AMS in subsection (c)(2) of this section, the costs for facilities that do not perform the functions and have the features specified in this section shall not be included in the surcharge provided for by this subsection unless an electric utility has received a waiver pursuant to subsection (g)(3) of this section. The costs of providing AMS services include those costs of AMS installed as part of a pilot program pursuant to this section. Costs of providing AMS for a particular customer class shall be surcharged only to customers in that customer class.

(2) **Carrying Costs.** The annualized carrying-cost rate to be applied to the unamortized balance of the AMS capital costs shall be the electric utility's authorized weighted-average cost of capital (WACC). If the commission has not approved a WACC for the electric utility within the last four years, the commission may set a new WACC to apply to the unamortized balance of the AMS capital costs. In each subsequent rate proceeding in which the commission resets the electric utility's WACC, the carrying-charge rate that is applied to the unamortized balance of the utility's AMS costs shall be correspondingly adjusted to reflect the new authorized WACC.

(3) **Surcharge Proceeding.** In the request for surcharge proceeding, an electric utility may propose a surcharge methodology, but the commission prefers the stability of a levelized amount, and an amortization period ranging from five to seven years, depending on the useful life of the meter. The commission may set the surcharge to reflect a deployment of advanced meters that is up to one-third of the electric utility's total meters over each calendar year, regardless of the rate of actual AMS deployment. The actual or expected net operating cost savings from AMS deployment, to the extent that the operating costs are not reflected in base rates, may be considered in setting the surcharge. If an electric utility that requests a surcharge does not have an approved Deployment Plan, the commission in the surcharge proceeding may reconcile the costs that the electric utility already spent on AMS in accordance with paragraph (6) of this subsection and may approve a Deployment Plan.

(4) **General Base Rate Proceeding while Surcharge is in Effect.** If the commission conducts a general base rate proceeding while a surcharge under this section is in effect, then the commission shall include the reasonable and necessary costs of installed AMS equipment in the base rates and decrease the surcharge accordingly, and permit reasonable recovery of any non-AMS metering equipment that has not yet been fully depreciated but has been replaced by the equipment installed under an approved Deployment Plan.

(5) **Annual Reports.** An electric utility shall file annual reports with the commission updating the cost information used in setting the surcharge. The annual reports shall include the actual costs spent to date in the deployment of AMS and the actual net operating cost savings from AMS deployment and how those numbers compare to the projections used to set the surcharge. During the annual report process, an electric utility may apply to update its surcharge, and the commission may set a schedule for such applications. For a levelized surcharge, the commission may alter the

length of the surcharge collection period based on review of information concerning changes in deployment costs or operating costs savings in the annual report or changes in WACC. An annual report filed with the commission shall not be a ratemaking proceeding, but an application by the electric utility to update the surcharge shall be a ratemaking proceeding.

(6) **Reconciliation Proceeding.** All costs recovered through the surcharge shall be reviewed in a reconciliation proceeding on a schedule to be determined by the commission. Nothwithstanding the preceding sentence, the electric utility may request multiple reconciliation proceedings, but no more frequently than once every three years. There is a presumption that costs spent in accordance with a Deployment Plan or amended Deployment Plan approved by the commission are reasonable and necessary. Any costs recovered through the surcharge that are found in a reconciliation proceeding not to have been spent or properly allocated, or not to be reasonable and necessary, shall be refunded to electric utility's customers. In addition, the commission shall make a final determination of the net operating cost savings from AMS deployment used to reduce the amount of costs that ultimately can be recovered through the surcharge. Accrual of interest on any refunded or surcharged amounts resulting from the reconciliation shall be at the electric utility's WACC and shall begin at the time the under or over recovery occurred.

(7) **Cross-subsidization and fees.** The electric utility shall account for its costs in a manner that ensures that there is no inappropriate cost allocation, cost recovery, or cost assignment that would cause cross-subsidization between utility activities and non-utility activities. The electric utility shall not charge a disconnection or reconnection fee that was approved by the commission prior to the effective date of this rule, for a disconnection or reconnection that is effectuated using the remote disconnection or connection capability of an advanced meter.

(l) **Time of Use Schedule.** Commission approval of a time of use schedule ("TOUS") pursuant to ERCOT protocols is not necessary prior to implementation of the new TOUS.

§25.131. Load Profiling and Load Research.

(a) **Purpose.** This section allocates responsibilities for obtaining load research information necessary to support the load profiling activities of the Electric Reliability Council of Texas (ERCOT), provides for access to that load profile research data by retail electric providers (REPs), and provides a method for recovery of costs by a person who successfully requests a new load profile.

(b) **Applicability.** This section applies to ERCOT, each transmission and distribution utility (TDU) that has a service territory within ERCOT, and each REP certified by the commission. For the purposes of this section, the term person may include a municipally owned utility or electric cooperative.

(c) **Load research responsibility**. Each TDU shall perform load research to support ERCOT's load profiling activities, as directed by ERCOT.

(1) ERCOT shall be responsible for load research sample design and sample point selection for ERCOT-directed load profiling and load research samples. ERCOT shall coordinate with each TDU to optimize load research programs of both ERCOT and the TDU. The same samples shall be used to support both the TDU's load research activities and ERCOT's load profile research needs whenever reasonably possible. Each TDU shall coordinate with ERCOT to synchronize its load research cycles and sample replacement with those of ERCOT.

(2) ERCOT, in consultation with TDUs, shall specify the manner of data collection for ERCOT load profile research samples and the means and frequency of transmission of such information to ERCOT. Each TDU shall adhere to the specifications for data collection and transmission specified by ERCOT.

(3) A TDU may recover its reasonable and necessary costs incurred in performing load profile research as required by this section.

(4) This section shall not be interpreted to require a TDU to redeploy any existing samples that were deployed less than five years before the effective date of this section, although this section shall also not be interpreted as addressing the appropriateness of continued deployment of existing TDU samples apart from an ERCOT request to do so. Notwithstanding the foregoing, the TDU shall deploy additional samples as requested by ERCOT in order to support ERCOT's load profiling activities.

(d) **Availability of load research data.** ERCOT shall make load profile research data collected under its direction for accepted load profiles available to all certified REPs.

(1) Notwithstanding the foregoing, a municipally-owned utility or electric cooperative that conducts load research activities shall have access to load research data maintained by ERCOT only if it shares statistically valid load research data from its own service territory with ERCOT in accordance with the provisions of subparagraphs (A)-(C) of this paragraph.

(A) A municipally-owned electric utility or electric cooperative may submit load research data only if it is obtained in a manner consistent with the Association of Edison Illuminating Companies (AEIC) load research standards and provided in the form and manner specified by ERCOT pursuant to subsection (c)(2) of this section.

(B) The municipally-owned electric utility or electric cooperative shall provide to ERCOT information concerning its load research sample design and any other relevant information required by ERCOT.

(C) ERCOT shall determine whether the load research data submitted by a municipally owned utility or electric cooperative is statistically valid sample data compiled in a manner consistent with the AEIC Load Profiling Guidelines.

(2) ERCOT shall make available customer level data collected under its direction for accepted load profiles for all customers as provided in this subsection, unless ERCOT concludes that due to the size, usage characteristics, or location of a sample, or other factors, there is a significant risk that release of customer level data for a sample would lead to the disclosure of the identity of the customer being sampled. ERCOT shall make available, as provided in this subsection, all other load profile research data on an aggregated basis, unless ERCOT determines that there is significant risk that disclosure of such aggregated data would lead to the disclosure of the identity of one or more sampled customers. In no event shall the location, name, account number, zip code, or electric service identifier (ESI-ID) of an individual customer in a load profile research sample be made available. The following information shall be made available for load profile research data provided on either an individualized or aggregated basis:

(A) customer class;
(B) TDU service area;
(C) weather zone; and
(D) interval usage, or average interval usage for aggregated data.

(3) ERCOT may not assess a charge to access the data specified in paragraph (2) of this subsection.

(e) **New load profiles and fee for use of load profiles.** ERCOT may establish new load profiles at the request of a REP or another person.

(1) A request for a new or modified load profile must include the requested information detailed in ERCOT's Load Profiling Guide.

(2) Any costs associated with developing the supporting data and documentation that is necessary for ERCOT's evaluation of the proposed profile change shall be the responsibility of the person initially requesting the profile change.

(3) Within six months of the effective date of this section, ERCOT shall establish and implement a process to collect a fee from any REP who seeks to assign customers to a non-ERCOT sponsored profile. The process shall include a method for other REPs who use the profile to compensate the original requester of the new profile and for ERCOT to notify TDUs which REPs are authorized to use the new profile. A TDU shall not, without authorization, assign a customer to a profile for which a REP or another person has paid the costs of developing the new profile.

§25.132. Definitions.

For purposes of this subchapter, the following terms have the following meanings unless the context indicates otherwise:

(1) **Meter tampering or tampering** -- any unauthorized alteration, manipulation, change, or modification of a meter or metering equipment, the diversion or bypass of the meter so that consumption is not properly registered and recorded, interference with or obstruction of meter communications, or alteration of meter data that could adversely affect the integrity of billing data or the electric utility's ability to collect, record, and process the data needed for billing or settlement. Meter tampering includes, but is not limited to, harming or defacing the electric utility's metering facilities, physically or electronically disorienting the meter, attaching objects to the meter, inserting objects into the meter, altering billing or settlement data, construction of electrical pathways that bypass the meter in whole or part, or other electrical or mechanical means of preventing the metering equipment from accurately registering, recording, and reporting accurate consumption information.

(2) **Meter repair and restoration charges** -- any fees or charges for replacing a meter, repairing a meter, restoring the condition of and securing metering facilities, removing any device that permits the meter to be bypassed, or repairing any other damage to the utility's facilities as authorized by the electric utility's tariff, including all other costs associated with the investigation and correction of the unauthorized use.

§25.133. Non-Standard Metering Service.

(a) **Purpose.** This section allows a customer whose standard meter is an advanced meter to choose to receive electric service through a non-standard meter and authorizes a transmission and distribution utility (TDU) to assess fees to recover the costs associated with this section from a customer who elects such a meter.

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

(1) Advanced meter--As defined in §25.130 of this title (relating to Advanced Metering).

(2) Non-standard meter--A meter that does not function as an advanced meter.

(c) **Initiation and termination of non-standard metering service.**

(1) **Initiation of non-standard metering service**.

(A) This subparagraph applies to a TDU that, on the date that the TDU begins offering non-standard metering service pursuant to subsection (g) of this section, has completed deployment of advanced meters except for customers for whom the TDU did not install advanced meters because of the requests of the customers. The TDU shall serve on such a customer by certified mail return receipt requested notice consistent with subparagraph (D) of this paragraph within 30 days of the date that the TDU begins offering non-standard metering service pursuant to subsection (g) of this section.

(B) This subparagraph applies to a TDU that has not completed deployment of advanced meters.

(i) This clause applies to a customer for whom the TDU has not, on the date that the TDU begins offering non-standard metering service pursuant to subsection (g) of this section, installed an advanced meter because of the request of the customer. The TDU shall serve on such a customer by certified mail return receipt requested notice consistent with subparagraph (D) of this paragraph within 30 days of the date that the TDU begins offering non-standard metering service pursuant to subsection (g) of this section.

(ii) This clause applies to a customer for whom, after the date that the TDU begins offering non-standard metering service pursuant to subsection (g) of this section, the TDU attempts to install an advanced meter as part of its advanced meter deployment plan but the customer requests non-standard metering service. The TDU shall promptly serve on such a customer by certified mail return receipt requested notice consistent with subparagraph (D) of this paragraph.

(C) For circumstances not addressed by subparagraph (A) or (B) of this paragraph in which a customer requests from the TDU non-standard metering service, ,the TDU shall provide notice consistent with subparagraph (D) of this paragraph within seven days of the customer's request, using an appropriate means of service.

(D) Pursuant to subparagraphs (A)-(C) of this paragraph, a TDU shall notify a customer of the following through a written acknowledgement.

(i) The customer will be required to pay the costs associated with the initiation of non-standard metering service and the ongoing costs associated with the manual reading of the meter, and other fees and charges that may be assessed by the TDU that are associated with the non-standard metering service;

(ii) The current one-time fees and monthly fee for non-standard metering service;

(iii) The customer may be required to wait up to 45 days to switch the customer's retail electric provider (REP), and may experience longer restoration times in case of a service interruption or outage;

(iv) The customer may be required by the customer's REP to choose a different product or service before initiation of the non-standard metering service, subject to any applicable charges or fees required under the customer's existing contract, if the customer is currently enrolled in a product or service that relies on an advanced meter; and

(v) For a customer that does not currently have an advanced meter, the date (60 days after service of the notice) by which the customer must provide a signed, written acknowledgement and payment of the one-time fee to the TDU prescribed by subsection (e)(3) of this section. If the signed, written acknowledgement and payment are not received within 60 days, the TDU will install an advanced meter on the customer's premises.

(E) The TDU shall retain the signed, written acknowledgement for at least two years after the non-standard meter is removed from the premises. The commission may adopt a form for the written acknowledgement.

(F) A TDU shall offer non-standard metering through the following means:

(i) disabling communications technology in an advanced meter if feasible;

(ii) if applicable, allowing the customer to continue to receive metering service using the existing meter if the TDU determines that it meets applicable accuracy standards;

(iii) if commercially available, an analog meter that meets applicable meter accuracy standards; and

(iv) a digital, non-communicating meter.

(G) The TDU shall not initiate the process to provide non-standard metering service before it has received the customer's payment and signed, written acknowledgement. The TDU shall initiate the approved standard market process to notify the customer's REP within three days of the TDU's receipt of the customer's payment and signed, written acknowledgement. Within 30 days of receipt of the payment of the one-time fee and the signed written acknowledgement from the customer, the TDU, using the approved standard market process, shall notify the customer's REP of the date the non-standard metering service was initiated.

(2) **Termination of non-standard metering service**. A customer receiving non-standard metering service may terminate that service by notifying the customer's TDU. The customer shall remain responsible for all costs related to non-standard metering service.

(d) **Other TDU obligations.**

(1) When a TDU completes a move-out transaction for a customer who was receiving non-standard metering service, the TDU shall install and/or activate an advanced meter at the premises.

(2) A TDU shall read a non-standard meter monthly. In order for the TDU to maintain a non-standard meter at the customer's premises, the customer must provide the TDU with sufficient access to properly operate and maintain the meter, including reading and testing the meter.

(e) **Cost recovery and compliance tariffs.** All costs incurred by a TDU to implement this section shall be borne only by customers who choose non-standard metering service. A customer receiving non-standard metering service shall be charged a one-time fee and a recurring monthly fee.

(1) Not later than 25 days after the effective date of this section, each TDU shall file a compliance tariff that is fully supported with testimony and documentation. The compliance tariff shall include one-time fees and a monthly fee for non-standard metering service and shall also include the fees for other discretionary services performed by the TDU that are affected by the customer's selection of non-standard metering service. Each TDU shall be allowed to recover the reasonable rate case expenses that it incurs under this subsection as part of the one-time fee, the monthly fee, or both.

The compliance tariff filing shall describe the extent to which the back-office costs that are new and fixed vary depending on the number of customers receiving non-standard metering service. Unless otherwise ordered, the TDU shall serve notice of the approved rates and the effective date of the approved rates within five working days of the presiding officer's final decision, to REPs that are authorized by the registration agent to provide service in the TDU's distribution service area. Notice under this paragraph may be served by email and, consistent with subsection (g) of this section, shall be served at least 45 days before the TDU begins offering non-standard metering service.

(2) A TDU may apply to change the fees approved pursuant to paragraph (1) of this subsection. The application must be fully supported with testimony and documentation. Each TDU shall be allowed to recover the reasonable rate case expenses that it incurs under this subsection as part of the one-time fee, the monthly fee, or both. Unless otherwise ordered, the TDU shall serve notice of the approved rates and the effective date of the approved rates within five working days of the presiding officer's final decision, to REPs that are authorized by the registration agent to provide service in the TDU's distribution service area. Notice under this paragraph may be served by email and, if possible, shall be served at least 45 days before the effective date of the rates.

(3) A TDU shall have a single recurring monthly fee for non-standard metering service and several one-time fees, one of which shall apply to the customer depending on the customer's circumstances. A one-time fee shall be charged to a customer that does not have an advanced meter at the customer's premises and will continue receiving metering service through the meter currently at the premises. For a customer that currently has an advanced meter at the premises, the fee shall vary depending on the type of meter that is installed to provide non-standard metering service, and the fee shall include the cost to remove the advanced meter and subsequently re-install an advanced meter once non-standard metering service is terminated. The one-time fee shall recover costs to initiate non-standard metering service. The monthly fee shall recover ongoing costs to provide non-standard metering service, including costs for meter reading and billing. Fixed costs not related to the initiation of non-standard metering service may be allocated between the one-time and monthly fees, and recovered through the monthly fee over a shortened period of time.

(f) **Retail electric product compatibility.** After receipt of the notice prescribed by subsection (c)(1)(D) of this section, if the customer's current product is not compatible with non-standard metering service, the customer's REP shall work with the customer to either promptly transition the customer to a product that is compatible with non-standard metering service or transfer the customer to another REP, subject to any applicable charges or fees required under the customer's existing contract. If the customer is unresponsive, the REP may transition the customer without the customer's affirmative consent to a market-based, month-to-month product that is compatible with non-standard metering service. Alternatively, if the customer is unresponsive the REP may transfer the customer to another REP pursuant to §25.493 (relating to Acquisition and Transfer of Customers from One Retail Electric Provider or Another) so long as the new REP serves the customer using a market-based, month-to-month product with a rate (excluding charges for non-standard metering service or other discretionary services) no higher than one of the tests prescribed by §25.498(c)(15)(A)-(C) of this title (relating to Prepaid Service). The REP shall promptly provide the customer notice that the customer has been transferred to a new product and, if applicable, to a new REP, and shall also promptly provide the new Terms of Service and Electricity Facts Label.

(g) **Implementation**. A TDU shall begin offering non-standard metering service pursuant to this section the later of 160 days from the effective date of this section or 45 days after the notice to REPs prescribed by subsection (e)(1) of this section.

§25.141. Central System or Nonsubmetered Master Metered Utilities.

(a) **Purpose.** This section implements Texas Utilities Code §184.052.

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

(1) **Apartment house --** One or more buildings containing two or more dwelling units rented primarily for nontransient use with rent paid at intervals of one week or longer.

(2) **Apartment house owner --** The legal titleholder of an apartment house or an individual, firm, or corporation purporting to be the landlord of tenants in the apartment house.

(3) **Central system utilities** -- Electricity consumed by a central air conditioning system, central heating system, central hot water system, or central chilled water system in an apartment house. The term does not include utilities directly consumed by a dwelling unit.

(4) **Customer** -- The individual, firm, or corporation in whose name a master meter is connected by a utility or that is served by a retail electric provider.

(5) **Dwelling unit** -- One or more rooms that are suitable for occupancy as a residence and that contain kitchen and bathroom facilities.

(6) **Nonsubmetered master metered utility service** -- Electric utility service that is master metered for an apartment house but is not submetered.

(7) **Utility** -- A public, private, or member-owned utility furnishing electricity service to an apartment house served by a master meter.

(c) **Records and reports.**

(1) The apartment house owner shall maintain and make available for inspection by the tenant during normal business hours:

(A) the billing from the utility to the apartment house owner for the current month and the 12 preceding months; and

(B) the calculation of the average cost per kilowatt-hour for the current month and the 12 preceding months which was used in assessing tenant utility billings. The average cost per kilowatt-hour shall be equal to the charges for the electric service plus applicable tax, less any penalties charged by the utility or retail electric provider to the apartment house owner for disconnect, and reconnect, late payment or other similar service charges, divided by the total number of billing units.

(2) All records shall be made available to the commission upon request.

(3) Records shall be made available at the resident manager's office during reasonable business hours or, if there is no resident manager, at the dwelling unit of the tenant at the convenience of both the apartment house owner and the tenant.

(d) **Calculation of costs.** Central system utilities costs shall be calculated based on metered kilowatt-hour of the central system during the same billing period as that of the utility. The metered kilowatt-hour of the central system shall be multiplied by the average cost per billing calculated according to all applicable industry standards. The cost of nonsubmetered master metered utilities shall be the total charges for electric service to the apartment house less any penalties charged by the utility or the retail electric provider to the apartment house owner for disconnect, reconnect, late payment or other similar service charges.

(e) **Billing.** All rental agreements between the apartment house owner and the tenants shall provide a clear written description of the method of the allocation of central system utilities or non-submetered master metered utilities for the apartment house. The method of allocation may be changed only after 90 days notice of the change to the tenants. The rental agreement for each apartment unit shall contain a statement of the average monthly bill for the previous calendar year for that apartment unit. If there is no rental agreement, apartment house owners shall provide the method of allocation in a separate written document.

(1) **Rendering and form of bill.**

(A) Bills shall be rendered for the same billing period as that of the utility or retail electric provider, generally monthly, unless service is rendered for less than that period.

(B) The allocation of central system utilities costs or nonsubmetered master metered utilities costs to tenants shall be based on one or a combination of the following methods.

(i) the total square footage living area of the dwelling unit as a percentage of the total square footage living area of all dwelling units of the apartment house and all heated and/or air-conditioned common areas. This percentage shall be stated in the rental agreement for each dwelling unit; and

(ii) the individually metered or submetered utility usage of the dwelling unit as a percentage of the sum of the individually metered or submetered usage of all dwelling units.

(C) Methods to allocate central system utility costs or nonsubmetered master metered utilities to tenants, other than the method outlined in this section, must be approved by the commission.

(D) Billings to the tenant shall not be included as part of the rental payment or as part of billings for any other service to the tenant. A separate billing must be issued or, if issued on a multi-item bill, utility billing information must be separate and distinct from any other charges on the bill. The bill may not include a deposit, late penalty, reconnect charge, or any other charges unless otherwise provided for by this chapter. A one-time penalty not to exceed 5.0% may be made on delinquent accounts. If such penalty is applied, the bill shall indicate the amount due if paid by the due date and the amount due if the late penalty is incurred. No late penalty may be applied unless agreed to by the tenant in a written lease which states the exact dollar or percentage amount of such late penalty.

(E) An apartment house owner may not impose additional charges on a tenant in excess of the actual charges imposed on the apartment house owner for utility consumption by the apartment house.

(2) **Due date.** The due date of the bill shall not be less than seven days after issuance. A bill for service is delinquent if not received by the party indicated on the bill by the due date. The postmark date, if any, on the envelope of the bill or on the bill itself shall constitute proof of the date of issuance. An issuance date on the bill shall constitute proof of the date of issuance if there is no postmark on the envelope or bill. If the due date falls on a holiday or weekend, the due date for payment purposes shall be the next workday after the due date.

(3) **Overbilling and underbilling.** If billings are found to be in error, the apartment house owner shall calculate a billing adjustment. If the tenant is due a refund, an adjustment shall be made for the entire period of the overcharges. If the tenant was undercharged, the apartment house owner may backbill the tenant for the amount which was underbilled. The backbilling is not to exceed six months unless the apartment house owner can produce records to identify and justify the additional amount of backbilling. If the underbilling is $25 or more, the apartment house owner shall offer to such tenant a deferred payment plan option, for the same length of time as that of the underbilling. Furthermore, adjustments for usage by a previous tenant may not be backbilled to the current tenant.

(4) **Discontinuance of electric service**. Disconnection of a dwelling unit by the apartment house owner is governed by Texas Property Code §92.008(b). Disconnection of electric service by a retail electric provider is governed by §25.483(k) of this title (relating to Disconnection of Service). Disconnection of service by an electric utility that is not a transmission and distributed utility is governed by §25.29(j) of this title (relating to Disconnection of Service).

(5) **Disputed bills and complaints**. In the event of a dispute between the tenant and the apartment house owner regarding any bill, the apartment house owner shall immediately make such investigation as shall be required by the particular case, and report the results thereof to the tenant. The investigation and report shall be completed within 30 days from the date the tenant notified the apartment house owner of the dispute. If the tenant is dissatisfied with the results of the investigation, the apartment house owner shall inform the tenant of the Public Utility Commission of Texas complaint process, giving the tenant the address and telephone number of the commission's Office of Customer Protection.

§25.142. Submetering for Apartments, Condominiums, and Mobile Home Parks.

(a) **Purpose.**
This section implements Texas Utilities Code §184.014.

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

(1) **Apartment house** -- One or more buildings containing more than five dwelling units, each of which is rented primarily for non-transient use with rent paid at intervals of one week or longer. The term includes a rented or owner-occupied residential condominium.

(2) **Dwelling unit** -- One or more rooms suitable for occupancy as a residence and that contain kitchen and bathroom facilities, or a mobile home in a mobile home park.

(3) **Master meter** -- A meter used to measure, for billing purposes, all electric usage of an apartment house or mobile home park, including common areas, common facilities, and dwelling units.

(4) **Month or monthly** -- The period between any two consecutive meter readings by the utility, either actual or estimated, at approximately 30-day intervals.

(5) **Owner** -- Any owner, operator, or manager of any apartment house or mobile home park engaged in electric submetering.

(6) **Electric submetering** -- Individual dwelling unit metering of electric service performed by the owner.

(c) **Records and reports.**

(1) The owner shall maintain and make available for inspection by the tenant the following records:

(A) the billing from the utility or retail electric provider to the apartment owner for the current month and the 12 preceding months;

(B) the calculation of the average cost per billing unit, *i.e.*, kilowatt-hour for the current month and the 12 preceding months;

(C)all submeter readings and tenant billings for the current month and the 12 preceding months;

(D) all submeter test results for the current month and the 12 preceding months.

(2) Records shall be made available at the resident manager's office during reasonable business hours or, if there is no resident manager, at the dwelling unit of the tenant at the convenience of both the apartment owner and tenant.

(3) All records shall be made available to the commission upon request.

(d) **Billing**. All rental agreements between the owner and the tenants shall clearly state that the dwelling unit is submetered, that the bills will be issued thereon, that electrical consumption charges for all common areas and common facilities will be the responsibility of the owner and not of the tenant, and that any disputes relating to the computation of the tenant's bill and the accuracy of the submetering device will be between the tenant and the owner. Each owner shall provide a tenant, at the time the lease is signed, a copy of this section or a narrative summary as approved by the commission to assure that the tenant is informed of his rights and the owner's responsibilities under this section.

(1) **Rendering and form of bill.**

(A) Bills shall be rendered for the same billing period as that of the electric utility, generally monthly, unless service is rendered for less than that period. Bills shall be rendered as promptly as possible following the reading of the submeters. The submeters shall be read within three days of the scheduled reading date of the electric utility's master meter.

(B) The billing unit shall be that used by the electric utility in its billing to the owner.

(C) The owner shall be responsible for determining that the energy billed to any dwelling unit shall be only for that submetered and consumed within that unit.

(D) Submetered billings shall not be included as part of the rental payment or as part of billings for any other service to the tenant. A separate billing must be issued or, if issued on a multi-item bill, submetered billing information must be separate and distinct from any other charges on the bill and conform to information required in subparagraph (H) of this paragraph. The submetered bill must clearly state "submetered electricity."

(E) The bill shall reflect only submetered usage. Utility consumption at all common facilities will be the responsibility of the owner and not of the tenant. Allocation of central systems for air conditioning, heating and hot water is not prohibited by this section as set forth in §25.141 of this title (relating to Central System or Nonsubmetered Master Metered Utilities).

(F) The owner shall not impose any extra charges on the tenant over and above those charges which are billed by the retail electric provider or utility to the owner. The bill may not include a deposit, late penalty, reconnect charge, or any other charges unless otherwise provided for by these sections.

(i) A one-time penalty not to exceed 5.0% may be made on delinquent accounts. If the penalty is applied, the bill shall indicate the amount due if paid by the due date and the amount due if the late penalty is incurred. No late penalty may be applied unless agreed to by the tenant in a written lease which states the exact dollar or percentage amount of the late penalty.

(ii) In a mobile home park a reconnect fee may be applied for a mobile home not leased by the mobile home park owner if service to the pad site tenant is disconnected for non-payment of submetered bills in accordance with subsection (e)(1) of this section. Such reconnect fee shall be calculated based on the average actual cost to the owner for the expenses associated with the reconnection, but under no circumstances shall exceed $10. No reconnect charge may be applied unless agreed to by the tenant in a written lease which states the exact dollar amount of such reconnect charge.

(G) The tenant's submeter bills shall be calculated in the following manner: after the electric bill is received from the utility or retail electric provider, the owner shall divide the net total charges for electrical consumption, plus applicable tax, by the total number of kilowatt-hours to obtain an average cost per kilowatt-hour. The average kilowatt-hour cost shall then be multiplied by each tenant's kilowatt-hour consumption to obtain the charge to the tenant. The computation of the average cost per kilowatt-hour shall not include any penalties charged by the utility or the retail electric provider to the owner for disconnect, reconnect, late payment, or other similar service charges.

(H) The tenant's electric submeter bill shall show all of the following information:

(i) the date and reading of the submeter at the beginning and at the end of the period for which the bill is rendered;

(ii) the number of billing units metered;

(iii) the computed rate per billing unit;

(iv) the total amount due for electricity used;

(v) a clear and unambiguous statement that the bill is not from the utility or retail electric provider, which shall be named in the statement;

(vi) the name and address of the tenant to whom the bill is applicable;

(vii) the name of the firm rendering the submetering bill and the name or title, address, and telephone number of the person or persons to be contacted in case of a billing dispute;

(viii) the date by which the tenant must pay the bill; and

(ix) the name, address, and telephone number of the party to whom payment is to be made.

(2) **Due date**. The due date of the bill shall not be less than seven days after issuance. A bill for submetered service is delinquent if not received by the party indicated on the bill by the due date. The postmark date, if any, on the envelope of the bill or on the bill itself shall constitute proof of the date of issuance. An issuance date on the bill shall constitute proof of the date of issuance if there is no postmark on the envelope or bill. If the due date falls on a holiday or weekend, the due date for payment purposes shall be the next work day after the due date.

(3) **Disputed bills**. In the event of a dispute between the tenant and the owner regarding any bill, the owner shall promptly make an investigation as shall be required by the particular case, and report the results to the tenant. The investigation and report shall be completed within 30 days from the date the tenant notified the owner of the dispute.

(4) **Tenant access to records**. The tenants of any dwelling unit whose electrical consumption is submetered shall be allowed by the owner to review and copy the master billing for the current month's billing period and for the 12 preceding months, and all submeter readings of the entire apartment house or mobile home park for the current month and for the 12 preceding months.

(5) **Estimated bills**. Estimated bills shall not be rendered unless the meter has been tampered with or is out of order, and shall be distinctly marked "estimated bill".

(6) **Overbilling and underbilling**. If submetered billings are found to be in error, the owner shall calculate a billing adjustment. If the tenant is due a refund, an adjustment shall be made for the entire period of the overcharges. If the tenant was undercharged, the owner may backbill the tenant for the amount which was underbilled. The backbilling is not to exceed six months unless the owner can produce records to identify and justify the additional amount of backbilling. If the underbilling is $50 or more, the owner shall offer to the tenant a deferred payment plan option, for the same length of time as that of the underbilling. However, in a mobile home park, the mobile home park owner may not disconnect electric service to a mobile home not leased by the mobile home park owner if the pad site tenant fails to pay charges arising from an underbilling more than six months prior to the date the tenant was initially notified of the amount of the undercharges and the total additional amount due. Furthermore, adjustments for usage by a previous tenant may not be backbilled to the current tenant.

(7) **Level and average payment plans**. An owner may offer a level payment plan or average payment plan consistent with this paragraph.

(A) The payment plan may be one of the following methods:

(i) A level payment plan allowing eligible tenants to pay on a monthly basis a fixed billing rate of one-twelfth of that tenant's estimated annual consumption at the appropriate rates, with provisions for quarterly adjustments as may be determined based on actual usage.

(ii) An average payment plan allowing tenants to pay on a monthly basis one-twelfth of the sum of that tenant's current month's consumption plus the previous 11 month's consumption (or an estimate thereof, for a new customer) at the appropriate customer class rates, plus a portion of any unbilled balance. Provisions for annual adjustments as may be determined based on actual usage shall be provided. If at the end of a year the owner determines that he has collected an amount different than he has been charged by the utility or retail electric provider, the owner must refund any overcollection and may surcharge any undercollection over the next year.

(B) Under either of the plans outlined in subparagraph (A) of this paragraph the owner is prohibited from charging the tenant any interest that may accrue. Any seasonal overcharges or undercharges will be carried by the owner of the complex.

(C) A mobile home park owner may disconnect service to a mobile home not leased by the mobile home park owner, pursuant to subsection (e) of this section, if the pad site tenant does not fulfill the terms of a level payment plan or an average payment plan.

(D) The owner may collect a deposit from all tenants entering into level payment plans or average payment plans; the deposit will not exceed an amount equivalent to one-sixth of the estimated annual billing. Notwithstanding any other provision in these sections, the owner may retain said deposit for the duration of the level or average payment plan; however, the owner shall pay interest on the deposit as is provided in §25.24 of this title (relating to Credit Requirements and Deposits).

(e) **Discontinuance of electric service.**

(1) **Application.** This subsection applies only to mobile homes in a mobile home park that are not leased by the mobile home park owner. Disconnection of any other dwelling unit by the owner is governed by Texas Property Code §92.008(b).

(2) **Disconnection for delinquent bills.**

(A) Electric service may be disconnected only for nonpayment of electric bills. A pad site tenant's electric service may be disconnected if a bill has not been paid within 12 days from the date of issuance and proper notice has been given. Proper notice shall consist of a separate mailing or hand delivery at least five days prior to a stated date of disconnection, with the words "termination notice" or similar language prominently displayed on the notice. The notice shall include the office or street address where a tenant can go during normal working hours to make arrangements for payment of the bill and for reconnection of service.

(B) Under these provisions, a pad site tenant's electric service may be discontinued only for nonpayment of electric service.

(3) **Disconnection on holidays or weekends**. Unless a dangerous condition exists, or unless the pad site tenant requests disconnection, electric service shall not be disconnected on a day, or on a day immediately preceding a day, when personnel of the mobile home park are not available for the purpose of making collections and reconnecting electric service.

(4) **Disconnection under special circumstances.**

(A) **Disconnection of ill and disabled.** A mobile home park owner shall not disconnect electric service to a pad site tenant when that tenant establishes that disconnection of electric service will cause some person residing at the tenant's mobile home to become seriously ill or more seriously ill;

(i) Each time a pad site tenant seeks to avoid disconnection of electric service under this subparagraph, the tenant must accomplish all of the following by the stated date of disconnection:

(I) have the person's attending physician (for purposes of this subsection, the term "physician" shall mean any public health official, including medical doctors, doctors of osteopathy, nurse practitioners, registered nurses, and any other similar public health official) call or contact the mobile home park owner by the stated date of disconnection;

(II) have the person's attending physician submit a written statement to the mobile home park owner; and

(III) enter into a deferred payment plan.

(ii) The prohibition against electric service termination provided by this subparagraph shall last 63 days from the issuance of the electric bill or a shorter period agreed upon by the mobile home park owner and the customer or physician.

(B) **Disconnection of energy assistance clients**. A mobile home park owner shall not disconnect electric service to a pad site tenant for a billing period in which the mobile home park owner receives a pledge, letter of intent, purchase order, or other notification that the energy assistance provider is forwarding sufficient payment to continue service; and

(C) **Disconnection during extreme weather.** A mobile home park owner shall not disconnect electric service to a pad site tenant on a day when:

(i) the previous day's highest temperature did not exceed 32 degrees Fahrenheit, and the temperature is predicted to remain at or below that level for the next 24 hours, according to the nearest National Weather Service (NWS) reports; or

(ii) the NWS issues a heat advisory for any county in which the mobile home park is located, or when such advisory has been issued on any one of the preceding two calendar days.

(f) **Submeters.**

(1) **Submeter requirements.**

(A) **Use of submeter**. All electrical energy sold by an owner shall be charged for by meter measurements.

(B) **Installation by owner**. Unless otherwise authorized by the commission, each owner shall be responsible for providing, installing, and maintaining all submeters necessary for the measurement of electrical energy to its tenants.

(2) **Submeter records**. Each owner shall keep the following records:

(A) **Submeter equipment record**. Each owner shall keep a record of all of its submeters, showing the tenant's address and date of the last test.

(B) **Records of submeter tests**. All submeter tests shall be properly referenced to the submeter record provided in this section. The record of each test made shall show the identifying number of the submeter, the standard meter and other measuring devices used, the date and kind of test made, by whom made, the error (or percentage of accuracy), and sufficient data to permit verification of all calculations.

(3) **Submeter unit indication.** Each meter shall indicate clearly the kilowatt-hours consumed by the tenant.

(4) **Submeter tests on request of tenant**. Each owner shall, upon the request of a tenant, and if the tenant so desires, in the tenant's or the tenant's authorized representative's presence, make a test of the accuracy of the tenant's submeter. The test shall be made during reasonable business hours at a time convenient to the tenant desiring to observe the test. If the submeter tests within the accuracy standards for self-contained watt-hour meters as established by the latest edition of American National Standards Institute, Incorporated, (ANSI), Standard C12 (American National Code for Electricity Metering), a charge of up to $15 may be charged the tenant for making the test. However, if the submeter has not been tested within a period of one year, or if the submeter's accuracy is not within the appropriate accuracy standards, no charge shall be made to the tenant for making the test. Following completion of any requested test, the owner shall promptly advise the tenant of the results of the test.

(5) **Bill adjustment due to submeter error**. If any submeter is found not to be within the accuracy standards in subsection (f)(4) of this section proper correction shall be made of previous readings. An adjusted bill shall be rendered in accordance with subsection (d)(6) of this section. If a submeter is found not to register for any period, unless bypassed or tampered with, the owner may make a charge for units used, but not metered, for a period not to exceed one month based on amounts used under similar conditions during periods preceding or subsequent thereto, or during the corresponding period in previous years.

(6) **Bill adjustment due to conversion**. If, during the 90-day period preceding the installation of meters or submeters, an owner increases rental rates, and such increase is attributable to increased costs of electric service, then such owner shall immediately reduce the rental rate by the amount of

such increase and shall refund all of the increase that has previously been collected within the 90-day period.

(7) **Location of submeters**. Submeters, service switches, or cut-off valves in conjunction with the submeters shall be installed in accordance with the latest edition of ANSI, Standard C12, and will be readily accessible for reading, testing, and inspection, with minimum interference and inconvenience to the tenant.

(8) **Submeter testing facilities and equipment**.

(A) **Qualified expert**. Each owner engaged in electric submetering shall engage an independent qualified expert to provide such instruments and other equipment and facilities as may be necessary to make the submeter tests required by this section. Such equipment and facilities shall generally conform to the ANSI, Standard C12, unless otherwise prescribed by the commission, and shall be available at all reasonable times for the inspection by its authorized representatives.

(B) **Portable standards**. Each owner engaged in electrical submetering shall, unless specifically excused by the commission, provide or utilize a testing firm which provides portable test instruments as necessary for testing billing submeters.

(C) **Reference standards**. Each owner shall provide or have access to suitable indicating instruments as reference standards for insuring the accuracy of shop and portable instruments used for testing billing submeters.

(D) **Testing of reference standards**. All reference standards shall be submitted once each year or on a scheduled basis approved by the commission to a standardizing laboratory of recognized standing, for the purpose of testing and adjustment.

(E) **Calibration of test equipment**. All shop and portable instruments used for testing billing submeters shall be calibrated by comparing them with a reference standard at least every 120 days during the time such test instruments are being regularly used. Test equipment shall at all times be accompanied by a certified calibration card signed by the proper authority, giving the date when it was last certified and adjusted. Records of certifications and calibrations shall be kept on file in the office of the owner.

(9) **Accuracy requirements for submeters.**

(A) **Limits**. No submeter that exceeds the test calibration limits for self-contained watt-hour meters as set by the ANSI, Standard C12, shall be placed in service or left in service. All electrical current transformers, potential transformers, or other such devices used in conjunction with an electric submeter shall be considered part of the submeter and must also meet test calibration and phase angle limits set by the ANSI Standard C12 and the ANSI Standard C57.13 for revenue billing. A nameplate shall be attached to each transformer and shall include or refer to calibration and phase angle data and other information required by the ANSI Standard C12 and the ANSI Standard C57.13 for revenue billing. Whenever on installation, periodic, or other tests, an electric submeter or transformer is found to exceed these limits, it shall be adjusted, repaired, or replaced.

(B) **Adjustments**. Submeters shall be adjusted as closely as possible to the condition of zero error. The tolerances are specified only to allow for necessary variations.

(10) **Submeter tests prior to installation**. No submeter shall be placed in service unless its accuracy has been established. If any submeter is removed from actual service and replaced by another submeter for any purpose whatsoever, it shall be properly tested and adjusted before being placed in service again.

(11) **Testing of electric submeters in service**. Standard electromechanical single stator watt-hour meters with permanent braking magnets shall be tested in accordance with the ANSI Standard C12 for periodic, variable interval, or statistical sampling testing programs. All other types of submeters shall be tested at least annually unless specified otherwise by the commission.

(12) **Restriction**. Unless otherwise provided by the commission, no dwelling unit in an apartment house or mobile home park may be submetered unless all dwelling units are submetered.

(13) **Same type meters required**. All submeters which are served by the same master meter shall be of the same type, such as induction or electronic.

§25.172. Goal for Natural Gas.

(a) **Applicability**. This section applies to a power generation company, municipally owned utility, or electric cooperative that installs new generation capacity in this state after January 1, 2000. The provisions of subsection (g) of this section shall apply to a municipally owned utility or an electric cooperative only if it has adopted customer choice pursuant to the Public Utility Regulatory Act (PURA) §40.051(a) or §41.051(a) respectively. This section does not apply to an electric utility not subject to PURA Chapter 39, pursuant to §39.102(c), until the expiration of its freeze period.

(b) **Purpose**. The purpose of this section is to encourage, to the extent permitted by law, owners of new generating capacity, other than capacity from renewable energy technologies, to use natural gas as their primary fuel source. The commission shall institute a natural gas energy credits trading program to ensure that 50% of all new generating capacity except, capacity from renewable energy technologies, installed in this state after January 1, 2000, uses natural gas as its primary fuel.

(c) **Definitions.**

(1) **New generating capacity** — Nameplate generating capacity of a facility installed in this state after January 1, 2000, except capacity based on a renewable energy technology. This definition of new generating capacity does not include modifications to previously installed generating facilities that merely increase the efficiency of, or reduce emissions from, such facilities. For the purposes of this section the phrase "new generating capacity purchased" refers to the purchase of all or part of an installed unit, and not to the purchase of capacity or energy from an installed unit.

(2) **Natural gas energy credit (NGEC)** — A NGEC shall be granted for each megawatt of new generating capacity fueled by natural gas. The commission shall issue NGECs to each power generation company, municipally owned utility, or electric cooperative that installs new, gas-fired generating capacity. Each credit shall be issued once and shall be valid so long as the plant meets reasonable performance standards; if a plant no longer meets reasonable performance standards or is retired, its associated NGECs shall be revoked.

(3) **Reasonable performance standards** — Those standards which, when applied to new natural gas-fired capacity, would reasonably be expected to maximize energy output consistent with industry standards widely accepted at the time of installation and for the technology employed.

(d) **Natural gas energy credit requirement.** Upon activation of the NGEC trading program the number of NGECs required to be owned or held by each power generation company, municipally owned utility, and electric cooperative in this state shall not be less than its new non-gas-fired generating capacity in megawatts. Upon retirement of new non-gas-fired generating capacity, the NGEC requirement shall be reduced by the capacity of the facility that is retired.

(1) The requirements of this section may be satisfied by owning new generating capacity fired primarily by natural gas, for which NGECs have not been sold to a third party, or by holding NGECs acquired from third parties, either in connection with purchasing capacity or on a stand-alone basis, or by any combination thereof.

(2) A power generation company, municipally owned utility, or electric cooperative that does not own new generation capacity shall not be required to obtain any natural gas credits.

(e) **Program activation.** The commission shall activate the natural gas energy credits trading program if it determines that within three years from the date of the evaluation, new generating capacity in Texas that is fueled primarily by natural gas may fall below 55% of all new generating capacity. However, the commission may accelerate or delay implementation of individual NGEC requirements in the event the commission determines that such action is in the public interest. This analysis shall be based on the annual reports filed pursuant to subsection (h) of this section. If the commission activates the program, it shall:

(1) require power generators, municipally owned utilities, and electric cooperatives to demonstrate that for each megawatt of new non-gas fired generating capacity it owns or holds natural gas energy credits equal to that amount of capacity; and

(2) Within 240 days, adopt rules that will determine the conditions for compliance and penalties for noncompliance with this section for each power generator, municipally owned utility, and electric cooperative.

(f) **Natural gas energy credit trading.** The commission shall be responsible for issuing, tracking and assigning serial numbers to NGECs in accordance with this section. The total number of NGECs at any time shall equal the amount of new gas-fired generating capacity (MW) that uses natural gas as its primary fuel source, less any NGECs revoked to reflect plant retirements or poor performance relative to the standards referred to in subsection (c)(4) of this section. NGECs may be traded among power generators, municipally owned utilities, electric cooperatives, and other interested parties.

(g) **Environmental benefits and "green" electricity.** Each retail electric provider, municipally owned utility, or electric cooperative that has adopted customer choice:

(1) may emphasize that natural gas produced in this state is the cleanest burning fossil fuel;

(2) may market electricity generated using natural gas produced in this state as environmentally beneficial and may label such generation as "green" electricity under this section if such electricity is generated exclusively from generating capacity based on natural gas technologies that use natural gas produced in this state. The use of fuel oil in a generating facility that otherwise relies on natural gas as its sole fuel shall not preclude labeling output from the facility as "green" if the fuel oil is used for:
   (A) emergency backup;
   (B) periodic testing; or
   (C) a lubricant in *de minimus* amounts; and

(3) shall provide sufficient proof, upon request, that any marketing representation that it makes that its electricity is "green" are consistent with this section.

(h) **Annual reports.**

(1) Beginning in 2001, no later than February 14th of each year, each registered power generation company, municipally owned utility, and electric cooperative shall file with the commission on a form prescribed by the commission, the following information regarding new generating facilities it owns or operates in Texas:
   (A) For each unit of new generating capacity:
      (i) plant location and name;
      (ii) nameplate capacity (in megawatts) of each unit;
      (iii) ownership share of each unit;
      (iv) primary fuel type of new generating capacity;
      (v) Texas Natural Resource Conservation Commission turbine or boiler permit number and date; and
      (vi) date that commercial operation began.
   (B) Forecasted generation additions by fuel type for the next three calendar years (for the next five calendar years if the fuel type is coal, lignite, or nuclear):
      (i) plant location and name;
      (ii) nameplate capacity (MW) of each unit;

(iii) ownership share of each unit;

(iv) primary fuel type of new generating capacity;

(v) Texas Natural Resource Conservation Commission turbine or boiler permit number and date; and

(vi) date that commercial operation will begin.

(C) Data on holdings of natural energy gas credits:

(i) current holdings of credits by serial number; and

(ii) any purchase or sale of credits by serial number during the previous calendar year.

(2) Based on the annual reports, not later that April 15th of each year, the commission shall award NGECs for new-gas fired capacity installed in the previous year.

(3) Beginning in 2001, and no later than May 15th of each year, the commission shall publish, in aggregate form only, the information submitted in compliance with this rule, including calculations that show whether the prior year's generating capacity in Texas is in compliance with this section and whether capacity for the following three years is likely to be in compliance with the natural gas usage goals, based on the forecast information submitted.

(i) **Texas natural gas – market conditions.** The commission shall consult with the Railroad Commission of Texas, which shall monitor the Texas natural gas industry and conduct appropriate market studies to determine whether an adequate supply of Texas natural gas for power generation exists. If necessary, the commission shall develop additional safeguards to ensure that natural gas produced in this state remains the preferred fuel for power generation.

§25.173. Goal for Renewable Energy.

(a) **Purpose.** The purposes of this section are:

(1) to ensure that the cumulative installed generating capacity from renewable energy technologies in this state totals 2,280 megawatts (MW) by January 1, 2007, 3,272 MW by January 1, 2009, 4,264 MW by January 1, 2011, 5,256 MW by January 1, 2013, and 5,880 MW by January 1, 2015, with a target of at least 500 MW of the total installed renewable capacity after September 1, 2005, coming from a renewable energy technology other than a source using wind energy, and that the means exist for the state to achieve a target of 10,000 MW of installed renewable capacity by January 1, 2025;

(2) to provide for a renewable energy credits trading program by which the renewable energy requirements established by the Public Utility Regulatory Act (PURA) §39.904(a) may be achieved in the most efficient and economical manner;

(3) to encourage the development, construction, and operation of new renewable energy resources at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial resources;

(4) to protect and enhance the quality of the environment in Texas through increased use of renewable resources; and

(5) to ensure that all customers have access to providers of energy generated by renewable energy resources pursuant to PURA §39.101(b)(3).

(b) **Application.** This section applies to power generation companies as defined in §25.5 of this title (relating to Definitions), and retail entities as defined in subsection (c) of this section.

(c) **Definitions.**

(1) **Compliance period** -- A calendar year beginning January 1 and ending December 31 of each year in which renewable energy credits are required of a retail entity.

(2) **Compliance premium** -- A premium awarded by the program administrator in conjunction with a renewable energy credit that is generated by a renewable energy source that is not powered by wind and meets the criteria of subsection (m) of this section. For the purpose of the renewable energy portfolio standard requirements, one compliance premium is equal to one renewable energy credit.

(3) **Designated representative** -- A responsible natural person authorized by the owners or operators of a renewable resource to register that resource with the program administrator. The designated representative must have the authority to represent and legally bind the owners and operators of the renewable resource in all matters pertaining to the renewable energy credits trading program.

(4) **Existing facilities** -- Renewable energy generators placed in service before September 1, 1999.

(5) **Generation offset technology** -- Any renewable technology that reduces the demand for electricity at a site where a customer consumes electricity. An example of this technology is solar water heating.

(6) **Microgenerator** -- A customer who owns one or more eligible renewable energy generating units with a rated capacity of less than 1MW operating on the customer’s side of the utility meter.

(7) **New facilities** -- Renewable energy generators placed in service on or after September 1, 1999. A new facility includes the incremental capacity and associated energy from an existing renewable facility achieved through repowering activities undertaken on or after September 1, 1999.

(8) **Off-grid generation** -- The generation of renewable energy in an application that is not interconnected to a utility transmission or distribution system.

(9) Opt-Out Notice -- Written notice submitted to the commission by a transmission-level voltage customer pursuant to PURA §39.904(m-1).

(10) **Program administrator --** The entity approved by the commission that is responsible for carrying out the administrative responsibilities related to the renewable energy credits trading program as set forth in subsection (g) of this section.

(11) **REC aggregator** -- An entity managing the participation of two or more microgenerators in the REC trading program.

(12) **REC offset (offset)** -- A REC offset represents one megawatt-hour (MWh) of renewable energy from an existing facility that is not eligible to earn renewable energy credits or compliance premiums.

(13) **Renewable energy credit (REC or credit)** -- A REC represents one MWh of renewable energy that is physically metered and verified in Texas and meets the requirements set forth in subsection (e) of this section.

(14) **Renewable energy credit account (REC account) --** An account maintained by the renewable energy credits trading program administrator for the purpose of tracking the production, sale, transfer, purchase, and retirement of RECs or compliance premiums by a program participant.

(15) **Renewable energy credits trading program (trading program) --** The process of awarding, trading, tracking, and submitting RECs or compliance premiums as a means of meeting the renewable energy requirements set out in subsection (d) of this section.

(16) **Renewable energy resource (renewable resource) --** A resource that produces energy derived from renewable energy technologies.

(17) **Renewable energy technology --** Any technology that exclusively relies on an energy source that is naturally regenerated over a short time and derived directly from the sun, indirectly from the sun, or from moving water or other natural movements and mechanisms of the environment. Renewable energy technologies include those that rely on energy derived directly from the sun, wind, geothermal, hydroelectric, wave, or tidal energy, or on biomass or biomass-based waste products, including landfill gas. A renewable energy technology does not rely on energy resources derived from fossil fuels, waste products from fossil fuels, or waste products from inorganic sources.

(18) **Renewable Portfolio Standard (RPS)** -- The amount of capacity required to meet the requirements of PURA §39.904 pursuant to subsection (h) of this section.

(19) **Repowered Facility --** An existing facility that has been modernized or upgraded to use renewable energy technology to produce electricity consistent with this rule.

(20) **Retail entity** -- Municipally-owned utilities, generation and transmission cooperatives and distribution cooperatives that offer customer choice; retail electric providers (REPs); and investor-owned utilities that have not unbundled pursuant to PURA Chapter 39.

(21) **Settlement period --** The first calendar quarter following a compliance period in which the settlement process for that compliance period takes place.

(22) **Small producer --** A renewable resource that is less than ten megawatts (MW) in size.

(23) **Transmission-level voltage customer --** A customer that receives electric service at 60 kilovolts (kV) or higher or that receives electric service directly through a utility-owned substation that is connected to the transmission network at 60 kV or higher.

(d) **Renewable energy credits trading program (trading program).** Renewable energy credits may be generated, transferred, and retired by renewable energy power generators certified pursuant to subsection (o) of this section, retail entities, and other market participants as set forth in this section.

(1) The program administrator shall apportion an RPS requirement among all retail entities as a percentage of the retail sales of each retail entity as set forth in subsection (h) of this section. Each retail entity shall be responsible for retiring sufficient RECs as set forth in subsections (h) and (l) of this section to comply with this section. The requirement to retire RECs to comply with this section becomes effective on the date a retail entity begins serving retail electric customers in Texas or, for an electric utility, as specified by law.

(2) A power generating company may participate in the program and may generate RECs and buy or sell RECs as set forth in subsection (l) of this section.

(3) RECs shall be credited on an energy basis as set forth in subsection (l) of this section.

(4) Municipally-owned utilities and distribution cooperatives that do not offer customer choice have no RPS requirement. However, regardless of whether the municipally-owned utility or distribution cooperative offers customer choice, a municipally-owned utility or distribution cooperative possessing renewable resources that meet the requirements of subsection (e) of this section may sell RECs generated by such a resource to retail entities as set forth in subsection (l) of this section.

(5) Except where specifically stated, the provisions of this section shall apply uniformly to all participants in the trading program.

(e) **Facilities eligible for producing RECs and compliance premiums in the renewable energy credits trading program.** For a renewable facility to be eligible to produce RECs and compliance premiums in the trading program it must be either a new facility, a small producer, or a repowered facility as defined in subsection (c) of this section and must also meet the requirements of this subsection.

(1) A renewable energy resource must not be ineligible under subsection (f) of this section and must register pursuant to subsection (o) of this section.

(2) For a renewable energy technology that requires fossil fuel, the facility's use of fossil fuel must not exceed 25.0% of the total annual fuel input on a British thermal unit (BTU) or equivalent basis.

(3) For a renewable energy technology that requires the use of fossil fuel that exceeds 2.0% of the total annual fuel input on a BTU or equivalent basis, RECs can only be earned on the renewable portion of the production. A renewable energy resource using a technology described by this paragraph shall comply with the following requirements:

(A) A meter shall be installed and periodic tests of the heat content of the fuel shall be conducted to measure the amount of fossil fuel input on a British thermal unit (BTU) or equivalent basis that is used at the facility;

(B) The renewable energy resource shall calculate the electricity generated by the unit in MWh, based on the BTUs (or equivalent) produced by the fossil fuel and the efficiency of the renewable energy resource, subtract the MWh generated with fossil fuel input from the total MWh of generation and report the renewable energy generated to the program administrator;

(C) The renewable energy resource shall report the generation to the program administrator in the measurements, format and frequency prescribed by the program administrator, which may include a description of the methodology for calculating the non-renewable energy produced by the resource; and

(D) The renewable energy resource is subject to audit to verify the accuracy of the data submitted to the program administrator and compliance with this section, to be conducted by the program administrator or an independent third party, as requested by the program administrator. If the program administrator requires a third party audit, the audit shall be performed at the expense of the renewable energy resource.

(4) The output of the facility must be readily capable of being physically metered and verified in Texas by the program administrator. Energy from a renewable facility that is delivered into a transmission system where it is commingled with electricity from non-renewable resources before being metered can not be verified as delivered to Texas customers. A facility is not ineligible by virtue of the fact that the facility is a generation-offset, off-grid, or on-site distributed renewable facility if it otherwise meets the requirements of this section.

(5) For a municipally owned utility operating a gas distribution system, any production or acquisition of landfill gas that is directly supplied to the gas distribution system is eligible to produce RECs based upon the conversion of the thermal energy in BTUs to electric energy in kWh using for the conversion factor the systemwide average heat rate of the gas-fired units of the combined utility's electric system as measured in BTUs per kWh.

(6) For industry-standard thermal technologies, the RECs can be earned only on the renewable portion of energy production. Furthermore, the contribution toward statewide renewable capacity megawatt goals from such facilities shall be equal to the fraction of the facility's annual MWh energy output from renewable fuel multiplied by the facility's nameplate MW capacity.

(7) For repowered facilities, a facility is eligible to earn RECs on all renewable energy produced up to a capacity of 150 MW. A repowered facility with a capacity greater than 150 MW may earn RECs for the energy produced in proportion to 150 divided by nameplate capacity.

(f) **Facilities not eligible for producing RECs in the renewable energy credits trading program.** A renewable facility is not eligible to produce RECs in the trading program if it is:

(1) A renewable energy capacity addition associated with an emissions reductions project described in Health and Safety Code §382.05193, that is used to satisfy the permit requirements in Health and Safety Code §382.0519; or

(2) An existing facility that is not a small producer as defined in subsection (c) of this section or has not been repowered as permitted under subsection (e) of this section.

(g) **Responsibilities of program administrator.** The commission shall appoint an independent entity to serve as the trading program administrator. At a minimum, the program administrator shall perform the following functions:

(1) Create accounts that track RECs or compliance premiums for each participant in the trading program;

(2) Award RECs or compliance premiums to registered renewable energy facilities on a quarterly basis based on verified meter reads;

(3) Award offsets to retail entities on an annual basis based on a nomination submitted by the retail entity pursuant to subsection (i) of this section;

(4) Annually record the retirement of RECs or compliance premiums that each retail entity submits;

(5) Retire RECs at the end of each REC's compliance life;

(6) Maintain public information on its website that provides trading program information to interested buyers and sellers of RECs;

(7) Create an exchange procedure where persons may purchase and sell RECs or compliance premiums. The exchange shall ensure the anonymity of persons purchasing or selling RECs or compliance premiums. The program administrator may delegate this function to an independent third party, subject to commission approval;

(8) Make public each month the total energy sales of retail entities in Texas for the previous month;

(9) Perform audits of generators participating in the trading program to verify accuracy of metered production data;

(10) Allocate the RPS requirement to each retail entity in accordance with subsection (h) of this section; and

(11) Submit an annual report to the commission. The program administrator shall submit a report to the commission on or before May 15 of each calendar year. The report shall contain information pertaining to renewable energy power generators and retail entities. At a minimum, the report shall contain:

(A) the amount of existing and new renewable energy capacity in MW installed in the state by technology type, the owner/operator of each facility, the date each facility began to produce energy, the amount of energy generated in megawatt-hours (MWh) each quarter for all capacity participating in the trading program or that was retired from service; and

(B) a listing of all retail entities participating in the trading program, each retail entity's RPS requirement, the number of offsets used by each retail entity, the number of RECs retired by each retail entity, the number of compliance premiums retired by each retail entity, a listing of all retail entities that were in compliance with the RPS requirement, a listing of all retail entities that failed to comply with the RPS requirement, and the deficiency of each retail entity that failed to retire sufficient RECs or compliance premiums to meet its RPS requirement.

(h) **Allocation of RPS requirement to retail entities.** The program administrator shall allocate RPS requirements among retail entities. Any renewable capacity that is retired before January 1, 2015 or any capacity shortfalls that arise due to purchases of RECs from out-of-state facilities shall be replaced and incorporated into the allocation methodology set forth in this subsection. Any changes to the allocation methodology to reflect replacement capacity shall occur two compliance periods after the facility is retired or the capacity shortfall occurs. The program administrator shall use the following methodology to determine the total annual RPS requirement for a given year and the final RPS allocation for individual retail entities:

(1) The total statewide RPS requirement for each compliance period shall be calculated in terms of MWh and shall be equal to the applicable capacity requirement set forth in this paragraph multiplied by 8,760 hours per year, multiplied by the appropriate capacity conversion factor set forth in subsection (k) of this section. The renewable energy capacity requirements for the compliance period beginning January 1, of the year indicated shall be:

(A) 1,400 MW of new resources in 2006;
(B) 1,400 MW of new resources in 2007;
(C) 2,392 MW of new resources in 2008;
(D) 2,392 MW of new resources in 2009;
(E) 3,384MW of new resources in 2010;
(F) 3,384 MW of new resources in 2011;
(G) 4,376 MW of new resources in 2012;
(H) 4,376 MW of new resources in 2013;
(I) 5,000 MW of new resources in 2014; and
(J) 5,000 MW of new resources for each year after 2014.

(2) The final RPS allocation for an individual retail entity for a compliance period shall be calculated as follows:

(A) Beginning with the 2008 compliance period, prior to the preliminary RPS allocation each retail entity's total retail energy sales are reduced to exclude the consumption of customers that opt out in accordance with subsection (j) of this section. Each retail entity's preliminary RPS allocation is determined by dividing its total retail energy sales in Texas by the total retail sales in Texas of all retail entities, and multiplying that percentage by the total statewide RPS requirement for that compliance period.

(B) The adjusted RPS allocation for each retail entity that is entitled to an offset is determined by reducing its preliminary RPS allocation by the offsets to which it qualifies, as determined under subsection (i) of this section, with the maximum reduction equal to the retail entity's preliminary RPS allocation. The total reduction for all retail entities is equal to the total usable offsets for that compliance period.

(C) Each retail entity's final RPS allocation for a compliance period shall be increased to recapture the total usable offsets calculated under subparagraph (B) of this paragraph. The additional RPS allocation shall be calculated by dividing the retail entity's preliminary RPS allocation by the total preliminary RPS allocation of all retail entities. This fraction shall be multiplied by the total usable offsets for that compliance period and this amount shall be added to the retail entity's adjusted RPS allocation to produce the retail entity's final RPS allocation for the compliance period.

(3) Concurrent with determining final individual RPS allocations for the current compliance period in accordance with this subsection, the program administrator shall recalculate the final RPS allocations for the previous compliance periods, taking into account corrections to retail sales resulting from resettlements. The difference between a retail entity's corrected final RPS allocation and its original final RPS allocation for the previous compliance periods shall be added to or subtracted from the retail entity's final RPS allocation for the current compliance period.

(i) **Nomination and award of REC offsets.**

(1) A REP, municipally-owned utility, G&T cooperative, distribution cooperative, or an affiliate of a REP, municipally-owned utility, or distribution cooperative, may apply offsets to meet all or a portion of its renewable energy purchase requirement, as calculated in subsection (h) of this section, only if those offsets were nominated in a filing with the commission by June 1, 2001.

(2) The program administrator shall award offsets consistent with the commission's actions to verify designations of REC offsets and with this section.

(3) REC offsets shall be equal to the average annual MWh output of an existing resource for the years 1991-2000 or the entire life of the existing resource, whichever is less.

(4) REC offsets qualify for use in a compliance period under subsection (h) of this section only to the extent that:

(A) The resource producing the REC offset has continuously since September 1, 1999 been owned by or its output has been committed under contract to a utility, municipally-owned utility, or cooperative (or successor in interest) nominating the resource under paragraph (1) of this subsection or, if the resource has been committed under a contract that expired after September 1, 1999 and before January 1, 2002, it was owned by or its output was committed under contract to a utility, municipally-owned utility, or cooperative on January 1, 2002; and

(B) The facility producing the REC offsets is operated and producing energy during the compliance period in a manner consistent with historic practice.

(5) If the production of energy from a facility that is eligible for an award of REC offsets ceases for any reason, or if the power purchase agreement with the facility's owner (or successor in interest)

that is referred to in paragraph (4)(A) of this subsection has lapsed or is no longer in effect, the retail entity shall no longer be awarded REC offsets related to the facility.

(6) REC offsets shall not be traded.

(j) **Opt-out notice.**

(1) A customer receiving electrical service at transmission-level voltage who submits an opt-out notice to the commission for the applicable compliance period shall have its load excluded from the RPS calculation.

(2) An investor-owned utility that is subject to a renewable energy requirement under this section shall not collect costs attributable to the REC program from an eligible customer who has submitted an opt-out notice. An investor-owned utility whose rates include the cost of RECs shall file a tariff to implement this subsection, not later than 30 days after the effective date of this section.

(3) A customer opt-out notice must be filed in the commission-designated project number before the beginning of a compliance period for the notice to be effective for that period. Each opt-out notice must include the name of the individual customer opting out, the customer's ESI IDs, the retail entities serving those ESI IDs, and the term for which the notice is effective, which may not exceed two years. The customer opting out must also provide the information included in the opt-out notice directly to ERCOT and may request that ERCOT protect the customer's ESI ID and consumption as confidential information. For notices submitted for the 2008 compliance period, a customer may amend a notice to include this information not later than January 15, 2009, if its initial notice did not include the information. A customer may revoke a notice under this subsection at any time prior to the end of a compliance period by filing a letter in the designated project number and providing notice to ERCOT.

(k) **Calculation of capacity conversion factor.** The capacity conversion factor used by the program administrator to allocate credits to retail entities shall be calculated during the fourth quarter of each odd-numbered compliance year. The capacity conversion factor shall:

(1) Be based on actual generator performance data for the previous two years for all renewable resources in the trading program during that period for which at least 12 months of performance data are available.

(2) Represent a weighted average of generator performance; and

(3) Use all actual generator performance data that is available for each renewable resource, excluding data for testing periods.

(l) **Production, transfer, and expiration of RECs.** The program administrator shall administer a trading program for renewable energy credits in accordance with the requirements of this subsection.

(1) The owner of a renewable resource shall earn one REC when a MWh is metered at that renewable resource. The program administrator shall record the energy in metered MWh and credit the REC account of the renewable resource that generated the energy on a quarterly basis. Quarterly production shall be rounded to the nearest whole MWh, with fractions of 0.5 MWh or greater rounded up.

(2) The transfer of RECs between parties shall be effective only when the transfer is recorded by the program administrator.

(3) The program administrator shall require that RECs be adequately identified prior to recording a transfer and shall issue an acknowledgement of the transaction to parties upon provision of adequate information. At a minimum, the following information shall be provided:
  (A) identification of the parties;
  (B) REC serial number, REC issue date, and the renewable resource that produced the REC;
  (C) the number of RECs to be transferred; and
  (D) the transaction date.

(4) A retail entity shall surrender RECs to the program administrator for retirement from the market in order to meet its RPS requirement for a compliance period. The program administrator will document all REC retirements annually.

(5) On or after each April 1, the program administrator will retire RECs that have not been retired by retail entities and have reached the end of their compliance life.

(6) The program administrator may establish a procedure to ensure that the award, transfer, and retirement of credits are accurately recorded.

(7) The issue date of RECs created by a renewable energy resource shall coincide with the beginning of the compliance period (calendar year) in which the credits are generated. All RECs shall have a compliance life of three compliance periods, after which the program administrator will retire them from the trading program.

(8) Each REC that is not used in the compliance period in which it was created may be banked and is valid for the next two compliance periods.

(m) **Target for renewable technologies other than wind power.** In order to meet the target of at least 500 MW of the total installed renewable capacity after September 1, 2005, coming from a renewable energy technology other than a source using wind energy as set forth in subsection (a)(1) of this section, the program administrator shall award compliance premiums to certified REC generators other than those powered by wind that were installed and certified by the commission pursuant to subsection (o) of this section after September 1, 2005. A compliance premium is created in conjunction with a REC.

(1) For eligible non-wind renewable technologies, one compliance premium shall be awarded for each REC awarded for energy generated after December 31, 2007.

(2) Except as provided in this subsection, the award, retirement, trade, and registration of compliance premiums shall follow the requirements of subsections (d), (l) and (n) of this section.

(3) A compliance premium may be used by any entity toward its RPS requirement pursuant to subsection (h) of this section.

(4) The program administrator shall increase the statewide RPS requirement calculated for each compliance period pursuant to subsection (h)(1) of this section by the number of compliance premiums retired during the previous compliance period.

(n) **Settlement process**. The first quarter following the compliance period shall be the settlement period during which the following actions shall occur:

(1) By January 31, the program administrator will notify each retail entity of its total RPS requirement for the previous compliance period as determined pursuant to subsection (h) of this section.

(2) By March 31, each retail entity shall submit credits or compliance premiums to the program administrator from its account equivalent to its RPS requirement for the previous compliance period. If the retail entity does not submit sufficient credits or compliance premiums to satisfy its obligation, the retail entity is subject to the penalty provisions in subsection (p) of this section.

(3) The program administrator may request the commission to adjust the deadlines set forth in this section if changes to the ERCOT settlement calendar or other factors affect the availability of reliable retail sales data.

(o) **Certification of renewable energy facilities.** The commission shall certify all renewable facilities that will produce either REC offsets, RECs, or compliance premiums for sale in the trading program. To be awarded RECs, or REC offsets, or compliance premiums, a power generator must complete the certification process described in this subsection. The program administrator shall not award offsets, RECs, or compliance premiums for energy produced by a power generator before it has been certified by the commission.

(1) The designated representative of the generating facility shall file an application with the commission on a form approved by the commission for each renewable energy generation facility. At a minimum, the application shall include the location, owner, technology, and rated capacity of the facility and shall demonstrate that the facility meets the resource eligibility criteria in subsection (e) of this section. Any subsequent changes to the information in the application shall be filed with the commission within 30 days of such changes.

(2) No later than 30 days after the designated representative files the certification form with the commission, the commission shall inform both the program administrator and the designated representative whether the renewable facility has met the certification requirements. At that time, the commission shall either certify the renewable facility as eligible to receive RECs, offsets, or compliance premiums, or describe any insufficiencies to be remedied. If the application is contested, the time for acting is extended for such time as is necessary for commission action.

(3) Upon receiving notice of certification of new facilities, the program administrator shall create a REC account for the designated representative of the renewable resource.

(4) The commission or program administrator may make on-site visits to any certified facility, and the commission shall decertify any facility if it is not in compliance with the provisions of this section.

(5) A decertified renewable generator may not be awarded RECs. However, any RECs awarded by the program administrator and transferred to a retail entity prior to the decertification remain valid.

(p) **Penalties and enforcement.** If by April 1 of the year following a compliance period the program administrator determines that a retail entity has not retired sufficient credits or compliance premiums to satisfy its allocation, the retail entity shall be subject to an administrative penalty pursuant to PURA §15.023, of $50 per MWh that is deficient.

(q) **Microgenerators and REC aggregators.** A REC aggregator may manage the participation of multiple microgenerators in the REC trading program. The program administrator shall assign to the REC aggregator all RECs accrued by the microgenerators who are under a REC management contract with the REC aggregator.

(1) The microgenerator's units shall be installed and connected to the grid in compliance with P.U.C. Substantive Rules, applicable interconnection standards adopted pursuant to the P.U.C. Substantive Rules, and federal rules.

(2) Notwithstanding subsection (e)(3) of this section, a REC aggregator may use any of the following methods for reporting generation to the program administrator, as long as the same method is used for each microgenerator in an aggregation unit, as defined by the REC aggregator. A REC aggregator may have more than one aggregation and may choose any of the methods listed below for each aggregation unit.

(A) The REC aggregator may provide the program administrator with production data that is measured and verified by an electronic meter that meets ANSI C12 standards and that will be separate from the aggregator's billing meter for the service address and for which the billing data and the renewable energy data are separate and verifiable data. Such actual data shall be collected and transmitted within a reasonable time and shall be subject to verification by the program administrator. REC aggregators using this method shall be awarded one REC for every MWh generated.

(B) The REC aggregator may provide the program administrator with sufficient information for the program administrator to estimate with reasonable accuracy the output of each unit, based on known or observed information that correlates closely with the generation output. REC aggregators using this method shall be awarded one REC for every 1.25 MWh generated. After installing the unit, the certified technician shall provide the microgenerator, the REC aggregator, and the program administrator the information required by the program administrator pursuant to this paragraph (2) of this subsection.

(C) A generating unit may have a meter that transmits actual generation data to the program administrator using applicable protocols and procedures. Such protocols and procedures shall require that actual data be collected and transmitted within a reasonable time. REC aggregators using this method shall be awarded one REC for every MWh generated.

(3) REC aggregators shall register with the commission and the program administrator and also register to participate in the REC trading program.

(4) A microgenerator participating in the REC trading program individually without the assistance of a REC aggregator shall comply with the requirements of this subsection.

§25.174. Competitive Renewable Energy Zones.

(a) Competitive Renewable Energy Zone Transmission Projects. In considering an application for a certificate of convenience and necessity (CCN) or CCN amendment for the addition of a second 345-kilovolt (kV) circuit on the Alibates-AJ Swope-Windmill-Ogallala-Tule Canyon transmission line, the commission is not required to consider the factors under Public Utility Regulatory Act (PURA) §37.056(c)(1) and (2).

(b) Designation of Competitive Renewable Energy Zones. The designation of Competitive Renewable Energy Zones (CREZs) pursuant to PURA §39.904(g) shall be made through one or more contested-case proceedings initiated by commission staff, for which the commission shall establish a procedural schedule. The commission shall consider the need for proceedings to determine CREZs in 2007.

- (1) Commission staff shall initiate a contested case proceeding upon receiving the information required by paragraph (2) of this subsection. Any interested entity that participates in the contested case may nominate a region for CREZ designation. An entity may submit any evidence it deems appropriate in support of its nomination, but it shall include information prescribed in paragraph (2)(A) - (C) of this subsection.
- (2) By December 1, 2006, the Electric Reliability Council of Texas (ERCOT) shall provide to the commission a study of the wind energy production potential statewide, and of the transmission constraints that are most likely to limit the deliverability of electricity from wind energy resources. ERCOT shall consult with other regional transmission organizations, independent organizations, independent system operators, or utilities in its analysis of regions of Texas outside the ERCOT power region. At a minimum, the study submitted by ERCOT shall include:
  - (A) a map and geographic descriptions of regions that can reasonably accommodate at least 1,000 megawatts (MW) of new wind-powered generation resources;
  - (B) an estimate of the maximum generating capacity in MW that each zone can reasonably accommodate and an estimate of the zone's annual production potential;
  - (C) a description of the improvements necessary to provide transmission service to the region, a preliminary estimate of the cost, and identification of the transmission service provider (TSP) or TSPs whose existing transmission facilities would be directly affected;
  - (D) an analysis of any potential combinations of zones that, in ERCOT's estimation, would result in significantly greater efficiency if developed together; and
  - (E) the amount of generating capacity already in service in the zone, the amount not in service but for which interconnection agreements (IAs) have been executed, and the amount under study for.
- (3) The Texas Department of Parks and Wildlife may provide an analysis of wildlife habitat that may be affected by renewable energy development in any candidate zone, and may submit recommendations for mitigating harmful impacts on wildlife and habitat.
- (4) In determining whether to designate an area as a CREZ and the number of CREZs to designate, the commission shall consider:
  - (A) whether renewable energy resources and suitable land areas are sufficient to develop generating capacity from renewable energy technologies;
  - (B) the level of financial commitment by generators; and
  - (C) any other factors considered appropriate by the commission as provided by PURA, including, but not limited to, the estimated cost of constructing transmission capacity necessary to deliver to electric customers the electric output from renewable energy resources in the candidate zone, and the estimated benefits of renewable energy produced in the candidate zone.

(5) The commission shall issue a final order within six months of the initiation by commission staff of a CREZ proceeding, unless it finds good cause to extend the deadline. For each new CREZ it orders, the commission shall specify:

(A) the geographic extent of the CREZ;

(B) major transmission improvements necessary to deliver to customers the energy generated by renewable resources in the CREZ, in a manner that is most beneficial and cost-effective to the customers, including new and upgraded lines identified by voltage level and a general description of where any new lines will interconnect to the existing grid;

(C) an estimate of the maximum generating capacity that the commission expects the transmission ordered for the CREZ to accommodate; and

(D) any other requirement considered appropriate by the commission as provided by PURA.

(6) The commission may direct a utility outside of ERCOT to file a plan for the development of a CREZ in or adjacent to its service area. The plan shall include the maximum generating capacity that each potential CREZ can reasonably accommodate; identify the transmission improvements needed to provide service to each CREZ; and include the cost of the improvements and a timetable for complying with all applicable federal transmission tariff requirements.

(c) **Level of financial commitment by generators for designating a CREZ.**

(1) A renewable energy developer's existing renewable energy resources, and pending or signed IAs for planned renewable energy resources, leasing agreements with landowners in a proposed CREZ, and letters of credit representing dollars per MW of proposed renewable generation resources, posted with ERCOT, that the developer intends to install and the area of interest are examples of financial commitment by developers to a CREZ. The commission may also consider projects for which a TSP, ERCOT, or another independent system operator is conducting an interconnection study; and any other factors for which parties have provided evidence as indications of financial commitment.

(2) A non-utility entity's commitment to build and own transmission facilities dedicated to delivering the output of renewable energy resources in a proposed CREZ to the transmission system of a TSP in Texas or a deposit or payment to secure or fund the construction of such transmission facilities by an electric utility or a transmission utility to deliver the output of a renewable generation project in Texas is an indication of the entity's financial commitment to a CREZ.

(d) **Plan to develop transmission capacity.**

(1) After the issuance of a final order in accordance with subsection (b)(5) of this section, entities interested in constructing the transmission improvements shall submit expressions of interest to the commission. The commission shall select the entity or entities responsible for constructing the transmission improvements, establish a schedule by which the improvements shall be completed, and specify any additional reporting requirements or other measures deemed appropriate by the commission to ensure that entities complete the ordered improvements in a timely manner.

(2) The commission shall develop a plan to construct transmission capacity necessary to deliver to electric customers, in a manner that is most beneficial and cost-effective to the customers, the electric output from renewable energy technologies in the CREZ.

(3) In developing the transmission capacity plan, the commission may consider:

(A) the estimated cost of constructing transmission capacity necessary to deliver to electric customers the electric output from renewable energy resources in the candidate zone;

(B) the estimated cost of additional ancillary services; and

(C) any other factors considered appropriate by the commission as provided by PURA.

(e) **Certificates of convenience and necessity.**

(1) Not later than three years after a commission final order designating a CREZ, each TSP selected to build and own transmission facilities for that CREZ shall file all required CREZ CCN applications. The commission may grant an extension to this deadline for good cause. The commission may establish a filing schedule for the CCN applications.

(2) A CCN application for a transmission project intended to serve a CREZ, except an application filed pursuant to paragraph (1) of this subsection or subsection (a) of this section, shall address all the criteria in PURA §37.056, including the criteria in PURA §37.056(c)(1) and (2).

(3) In determining whether financial commitment for a CREZ is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities for the CREZ, the commission shall consider the following evidence of financial commitment by renewable generators:

(A) capacity represented by installed generation located in one or more of the counties that lie in whole or in part within the CREZ;

(B) capacity represented by generation projects under construction that are located in one or more of the counties that lie in whole or in part within the CREZ and that will be operational within six months of the final order in a financial commitment proceeding. Evidence that the project will be operational within six months may include documentation showing that a construction contractor has been hired, that preliminary site work has begun, that the project financing has closed, or similar indicators of the status of the project;

(C) capacity represented by planned generation projects that are located in one or more of the counties that lie in whole or in part within the CREZ and that have a signed IA with a TSP that has been defined in subsection (a)(2)(E) of this section designated to build and own transmission facilities for that CREZ; and

(D) capacity represented by collateral posted by generators for the CREZ that complies with paragraph (7) of this subsection.

(4) Financial commitment for a CREZ is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities for the CREZ if the sum of the renewable generating capacity under any combination of paragraph (3)(A), (B), (C), and (D) of this subsection is at least 50% of the designated generating capacity for the CREZ. Fifty percent of the designated generating capacity for the Panhandle A CREZ approved by the commission in Docket Number 33672 shall be considered to be 1,595.5 MW. Fifty percent of the designated generating capacity for the Panhandle B CREZ approved by the commission in Docket Number 33672 shall be considered to be 1,196.5 MW.

(5) Installed renewable generation, renewable generation projects under construction, and planned renewable generation projects with signed IAs in the McCamey, Central, and Central West CREZs approved by the commission in Docket Number 33672 satisfy the financial commitment test set forth in paragraph (4) of this subsection for those CREZs and therefore financial commitment by renewable generators for those CREZs is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities for those CREZs. This finding of sufficient financial commitment shall be recognized in the CCN proceedings for transmission facilities for those CREZs and shall not be addressed further in those proceedings.

(6) Commission staff shall initiate a single proceeding for the commission to determine whether there is sufficient financial commitment under PURA §39.904(g)(3) by renewable generators for the Panhandle A and Panhandle B CREZs approved by the commission in Docket Number 33672 to grant CCNs for transmission facilities for those CREZs. If the commission determines that there is sufficient financial commitment for one of those CREZs, that finding shall be recognized in the CCN proceedings for transmission facilities for that CREZ, as identified in the commission's order in the proceeding initiated pursuant to this paragraph, and shall not be addressed further in the

CCN proceedings. If the commission determines that the Panhandle A or Panhandle B CREZ does not satisfy the financial commitment test in paragraph (4) of this subsection, the commission may:

(A) consider other evidence of financial commitment that the commission finds relevant under PURA §39.904(g)(3);

(B) find that the financial commitment requirement for that CREZ has been met if the commission determines that significant financial commitment exists in that CREZ and that the CREZ is sufficiently interrelated with a CREZ that has satisfied the financial commitment test;

(C) delay the filing of CREZ CCN applications for that CREZ until the commission conducts a subsequent proceeding in which it finds sufficient financial commitment for that CREZ in accordance with the financial commitment provisions of this subsection; or

(D) take other appropriate action.

(7) A renewable generator that elects to post collateral pursuant to paragraph (3)(D) of this subsection shall comply with the following requirements:

(A) The renewable generator shall provide a letter of intent to post collateral in a proceeding conducted pursuant to paragraph (6) of this subsection. The renewable generator shall then post the collateral no later than 30 days after the commission issues an interim order finding sufficient financial commitment by renewable generators for the CREZ. If the renewable generators post sufficient collateral, the commission may enter a final order with findings that reflect the adequacy of the financial commitment for the CREZ. If the renewable generators do not post sufficient collateral, the commission may enter a final order with findings that reflect the inadequacy of the financial commitments for the CREZ.

(B) A renewable generator shall post collateral equal to $15,350 per MW of its planned project capacity, or $10,000 per MW if the capacity is supported by leasing agreements with landowners that convey a right or option for a period of at least 20 years to develop and operate a renewable energy project based on a conversion factor of 60 acres per MW for a wind energy project.

(C) A renewable generator planning to build a project in a CREZ shall post collateral with the TSP with which it will interconnect in the CREZ or, if the TSP with which it will interconnect has not been determined, with any TSP that has been designated to build and own transmission facilities for that CREZ.

(D) A renewable generator may post collateral by providing a cash deposit, letter of credit, or guaranty agreement from an entity with an investment-grade credit rating. A TSP shall require a renewable generator that posts a guaranty agreement to provide another form of collateral if the guarantor loses its investment-grade credit rating or declares bankruptcy. If the renewable generator does not provide another form of collateral, the commission may take appropriate action including seeking administrative penalties.

(8) A TSP that receives collateral from a renewable generator pursuant to paragraph (7) of this subsection shall handle that collateral in accordance with the following provisions.

(A) If a renewable generator signs an IA with the TSP and posts any collateral required by the TSP to secure the construction of collection facilities, the TSP shall return to the generator all collateral received from that generator.

(B) If a renewable generator does not sign an IA with the TSP and post any collateral required by the TSP to secure the construction of collection facilities within 90 days after the TSP notifies it that the transmission system is capable of accommodating the renewable generator's renewable energy facility, the TSP shall retain the collateral received from the generator as an offset to the cost of the transmission facilities the TSP constructs for the CREZ and shall take all reasonable measures to execute any non-cash collateral.

(9) In a CREZ CCN application, a TSP may propose modifications to the transmission facilities described in a CREZ order if such improvements would reduce the cost of transmission or increase the amount of generating capacity that transmission improvements for the CREZ can accommodate. The commission may direct ERCOT to review modifications proposed by the TSP.

(10) Findings in Docket Numbers 33672, 35665, and 36146 and the commission's finding in paragraph (5) of this subsection establish that the level of financial commitment is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities designated as a Default Project in ordering paragraph 1 of the Order in Docket Number 36146 and for transmission facilities designated as a Priority Project in finding of fact 136 in the Order on Rehearing in Docket Number 33672. This finding of sufficient financial commitment shall be recognized in all pending and future CCN proceedings for Default and Priority Projects and shall not be addressed further in those proceedings.

(f) **Excess development in a CREZ.** If the aggregate level of renewable energy capacity for which transmission service is requested for a CREZ exceeds the maximum level of renewable capacity specified in the CREZ order, and if the commission determines that the security constrained economic dispatch mechanism used in the power region to establish a priority in the dispatch of CREZ resources is insufficient to resolve the congestion caused by excess development, the commission may initiate a proceeding and may consider limiting interconnection to and/or establishing dispatch priorities regarding the transmission system in the CREZ, and identifying the developers whose projects may interconnect to the transmission system in the CREZ under special protection schemes.

§25.181. Energy Efficiency Goal.

(a) **Purpose**. The purpose of this section is to ensure that:

(1) electric utilities administer energy efficiency incentive programs in a market-neutral, nondiscriminatory manner and do not offer competitive services, except as permitted in §25.343 of this title (relating to Competitive Energy Services) or this section;

(2) all customers, in all eligible customer classes and all areas of an electric utility's service area, have a choice of and access to the utility's portfolio of energy efficiency programs that allow each customer to reduce energy consumption, summer and winter peak demand, or energy costs; and

(3) each electric utility annually provides, through market-based standard offer programs, targeted market-transformation programs, or utility self-delivered programs, incentives sufficient for residential and commercial customers, retail electric providers, and energy efficiency service providers to acquire additional cost-effective energy efficiency, subject to EECRF caps established in subsection (f)(7) of this section, for the utility to achieve the goals in subsection (e) of this section.

(b) **Application**. This section applies to electric utilities.

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

(1) **Affiliate --**

(A) A person who directly or indirectly owns or holds at least 5.0% of the voting securities of an energy efficiency service provider;

(B) A person in a chain of successive ownership of at least 5.0% of the voting securities of an energy efficiency service provider;

(C) A corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by an energy efficiency service provider;

(D) A corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by:

(i) a person who directly or indirectly owns or controls at least 5.0% of the voting securities of an energy efficiency service provider; or

(ii) a person in a chain of successive ownership of at least 5.0% of the voting securities of an energy efficiency service provider; or

(E) A person who is an officer or director of an energy efficiency service provider or of a corporation in a chain of successive ownership of at least 5.0% of the voting securities of an energy efficiency service provider;

(F) A person who actually exercises substantial influence or control over the policies and actions of an energy efficiency service provider;

(G) A person over which the energy efficiency service provider exercises the control described in subparagraph (F) of this paragraph;

(H) A person who exercises common control over an energy efficiency service provider, where "exercising common control over an energy efficiency service provider" means having the power, either directly or indirectly, to direct or cause the direction of the management or policies of an energy efficiency service provider, without regard to whether that power is established through ownership or voting of securities or any other direct or indirect means; or

(I) A person who, together with one or more persons with whom the person is related by ownership, marriage or blood relationship, or by action in concert, actually exercises substantial influence over the policies and actions of an energy efficiency service provider even though neither person may qualify as an affiliate individually.

(2) **Baseline --** A relevant condition that would have existed in the absence of the energy efficiency project or program being implemented, including energy consumption that would have occurred. Baselines are used to calculate program-related demand and energy savings. Baselines can be defined as either project-specific baselines or performance standard baselines (*e.g.*, building codes).

(3) **Claimed savings** -- Values reported by an electric utility after the energy efficiency activities have been completed, but prior to the time an independent, third-party evaluation of the savings is performed. As with projected savings estimates, these values may utilize results of prior evaluations and/or values in technical reference manuals. However, they are adjusted from projected savings estimates by correcting for any known data errors and actual installation rates and may also be adjusted with revised values for factors such as per-unit savings values, operating hours, and savings persistence rates. Can be indicated as first year, annual demand or energy savings, and/or lifetime energy or demand savings values. Can be indicated as gross savings and/or net savings values.

(4) **Commercial customer --** A non-residential customer taking service at a metered point of delivery at a distribution voltage under an electric utility's tariff during the prior program year or a non-profit customer or government entity, including an educational institution. For purposes of this section, each metered point of delivery shall be considered a separate customer.

(5) **Competitive energy efficiency services --** Energy efficiency services that are defined as competitive under §25.341 of this title (relating to Definitions).

(6) **Conservation load factor --** The ratio of the annual energy savings goal, in kilowatt hours (kWh), to the peak demand goal for the year, measured in kilowatts (kW) and multiplied by the number of hours in the year.

(7) **Deemed savings calculation --** An industry-wide engineering algorithm used to calculate energy and/or demand savings of the installed energy efficiency measure that has been developed from common practice that is widely considered acceptable for the measure and purpose, and is applicable to the situation being evaluated. May include stipulated assumptions for one or more parameters in the algorithm, but typically requires some data associated with actual installed measure. An electric utility may use the calculation with documented measure-specific assumptions, instead of energy and peak demand savings determined through measurement and verification activities or the use of deemed savings.

(8) **Deemed savings value --** An estimate of energy or demand savings for a single unit of an installed energy efficiency measure that has been developed from data sources and analytical methods that are widely considered acceptable for the measure and purpose, and is applicable to the situation being evaluated. An electric utility may use deemed savings values instead of energy and peak demand savings determined through measurement and verification activities.

(9) **Demand --** The rate at which electric energy is used at a given instant, or averaged over a designated period, usually expressed in kW or megawatts (MW).

(10) **Demand savings --** A quantifiable reduction in demand.

(11) **Eligible customers --** Residential and commercial customers. In addition, to the extent that they meet the criteria for participation in load management standard offer programs developed for industrial customers and implemented prior to May 1, 2007, industrial customers are eligible customers solely for the purpose of participating in such programs.

(12) **Energy efficiency --** Improvements in the use of electricity that are achieved through customer facility or customer equipment improvements, devices, processes, or behavioral or operational changes that produce reductions in demand or energy consumption with the same or higher level of end-use service and that do not materially degrade existing levels of comfort, convenience, and productivity.

(13) **Energy Efficiency Cost Recovery Factor (EECRF) --** An electric tariff provision, compliant with subsection (f) of this section, ensuring timely and reasonable cost recovery for utility

expenditures made to satisfy the goal of PURA §39.905 that provide for a cost-effective portfolio of energy efficiency programs pursuant to this section.

(14) **Energy efficiency measures --** Equipment, materials, and practices, including practices that result in behavioral or operational changes, implemented at a customer's site on the customer's side of the meter that result in a reduction at the customer level and/or on the utility's system in electric energy consumption, measured in kWh, or peak demand, measured in kW, or both. These measures may include thermal energy storage and removal of an inefficient appliance so long as the customer need satisfied by the appliance is still met.

(15) **Energy efficiency program --** The aggregate of the energy efficiency activities carried out by an electric utility under this section or a set of energy efficiency projects carried out by an electric utility under the same name and operating rules.

(16) **Energy efficiency project --** An energy efficiency measure or combination of measures undertaken in accordance with a standard offer, market transformation program, or self-delivered program.

(17) **Energy efficiency service provider --** A person or other entity that installs energy efficiency measures or performs other energy efficiency services under this section. An energy efficiency service provider may be a retail electric provider or commercial customer, provided that the commercial customer has a peak load equal to or greater than 50 kW. An energy efficiency service provider may also be a governmental entity or a non-profit organization, but may not be an electric utility.

(18) **Energy savings --** A quantifiable reduction in a customer's consumption of energy that is attributable to energy efficiency measures, usually expressed in kWh or MWh.

(19) **Estimated useful life (EUL) --** The number of years until 50% of installed measures are still operable and providing savings, and is used interchangeably with the term "measure life". The EUL determines the period of time over which the benefits of the energy efficiency measure are expected to accrue.

(20) **Evaluated savings --** Savings estimates reported by the EM&V contractor after the energy efficiency activities and an impact evaluation have been completed. Differs from claimed savings in that the EM&V contractor has conducted some of the evaluation and/or verification activities. These values may rely on claimed savings for factors such as installation rates and the Technical Reference Manual for values such as per unit savings values and operating hours. These savings estimates may also include adjustments to claimed savings for data errors, per unit savings values, operating hours, installation rates, savings persistence rates, or other considerations. Can be indicated as first year, annual demand or energy savings, and/or lifetime energy or demand savings values. Can be indicated as gross savings and/or net savings values.

(21) **Evaluation --** The conduct of any of a wide range of assessment studies and other activities aimed at determining the effects of a program; or aimed at understanding or documenting program performance, program or program-related markets and market operations, program-induced changes in energy efficiency markets, levels of demand or energy savings, or program cost-effectiveness. Market assessment, monitoring, and evaluation, and measurement and verification (M&V) are aspects of evaluation.

(22) **Evaluation, measurement, and verification (EM&V) contractor --** One or more independent, third-party contractors selected and retained by the commission to plan, conduct, and report on energy efficiency evaluation activities, including verification.

(23) **Free driver --** Customers who do not directly participate in an energy efficiency program, but who undertake energy efficiency actions in response to program activity.

(24) **Free rider --** A program participant who would have implemented the program measure or practice in the absence of the program. Free riders can be total, in which the participant's activity would have completely replicated the program measure; partial, in which the participant's activity would have partially replicated the program measure; or deferred, in which the participant's

activity would have completely replicated the program measure, but at a time after the time the program measure was implemented.

(25) **Growth in demand --** The annual increase in demand in the Texas portion of an electric utility's service area at time of peak demand, as measured in accordance with this section.

(26) **Gross savings --** The change in energy consumption and/or demand that results directly from program-related actions taken by participants in an efficiency program, regardless of why they participated.

(27) **Hard-to-reach customers --** Residential customers with an annual household income at or below 200% of the federal poverty guidelines.

(28) **Impact evaluation --** An evaluation of the program-specific, directly induced changes (e.g., energy and/or demand reduction) attributable to an energy efficiency program.

(29) **Incentive payment --** Payment made by a utility to an energy efficiency service provider, an end-use customer, or third-party contractor to implement and/or attract customers to energy efficiency programs, including standard offer, market transformation and self-delivered programs.

(30) **Industrial customer --** A for-profit entity engaged in an industrial process taking electric service at transmission voltage, or a for-profit entity engaged in an industrial process taking electric service at distribution voltage that qualifies for a tax exemption under Tax Code §151.317 and has submitted an identification notice pursuant to subsection (w) of this section.

(31) **Inspection --** Examination of a project to verify that an energy efficiency measure has been installed, is capable of performing its intended function, and is producing an energy savings or demand reduction equivalent to the energy savings or demand reduction reported towards meeting the energy efficiency goals of this section.

(32) **Installation rate --** The percentage of measures that receive incentives under an energy efficiency program that are actually installed in a defined period of time. The installation rate is calculated by dividing the number of measures installed by the number of measures that receive incentives under an efficiency program in a defined period of time.

(33) **International performance measurement and verification protocol (IPMVP) --** A guidance document issued by the Efficiency Valuation Organization with a framework and definitions describing the M&V approaches.

(34) **Lifetime energy (demand) savings --** The energy (demand) savings over the lifetime of an installed measure(s), project(s), or program(s). May include consideration of measure estimated useful life, technical degradation, and other factors. Can be gross or net savings.

(35) **Load control --** Activities that place the operation of electricity-consuming equipment under the control or dispatch of an energy efficiency service provider, an independent system operator, or other transmission organization or that are controlled by the customer, with the objective of producing energy or demand savings.

(36) **Load management --** Load control activities that result in a reduction in peak demand, or a shifting of energy usage from a peak to an off-peak period or from high-price periods to lower price periods.

(37) **Market transformation program --** Strategic programs intended to induce lasting structural or behavioral changes in the market that result in increased adoption of energy efficient technologies, services, and practices, as described in this section.

(38) **Measurement and verification --** A subset of program impact evaluation that is associated with the documentation of energy or demand savings at individual sites or projects using one or more methods that can involve measurements, engineering calculations, statistical analyses, and/or computer simulation modeling. M&V approaches are defined in the IPMVP.

(39) **Net savings --** The total change in load that is attributable to an energy efficiency program. This change in energy and/or demand use shall include, implicitly or explicitly, consideration of appropriate factors. These factors may include free ridership, participant and non-participant spillover, induced market effects, changes in the level of energy service, and/or other non-program causes of changes in energy use and/or demand.

(40) **Net-to-gross --** A factor representing net program savings divided by gross program savings that is applied to gross program impacts to convert them into net program impacts. The factor may be made up of a variety of factors that create differences between gross and net savings, commonly considering the effects of free riders and spillover.

(41) **Non-participant spillover --** Energy savings that occur when a program non-participant installs energy efficiency measures or applies energy savings practices as a result of a program's influence.

(42) **Off-peak period --** Period during which the demand on an electric utility system is not at or near its maximum. For the purpose of this section, the off-peak period includes all hours that are not in the peak period.

(43) **Participant spillover --** The additional energy savings that occur when a program participant independently installs incremental energy efficiency measures or applies energy savings practices after having participated in the efficiency program as a result of the program's influence.

(44) **Peak demand --** Electrical demand at the times of highest annual demand on the utility's system. Peak demand refers to Texas retail peak demand and, therefore, does not include demand of retail customers in other states or wholesale customers.

(45) **Peak demand reduction --** Reduction in demand on the utility's system at the times of the utility's summer peak period or winter peak period.

(46) **Peak period --** For the purpose of this section, the peak period consists of the hours from one p.m. To seven p.m., during the months of June, July, August, and September, and the hours of 6 to 10 a.m. and 6 to 10 p.m., during the months of December, January, and February, excluding weekends and Federal holidays.

(47) **Program year --** A year in which an energy efficiency incentive program is implemented, beginning January 1 and ending December 31.

(48) **Projected savings --** Values reported by an electric utility prior to the time the energy efficiency activities are implemented. Are typically estimates of savings prepared for program and/or portfolio design or planning purposes. These values are based on pre-program or portfolio estimates of factors such as per-unit savings values, operating hours, installation rates, and savings persistence rates. These values may utilize results of prior evaluations and/or values in the Technical Reference Manual. Can be indicated as first year, annual demand or energy savings, and/or lifetime energy or demand savings values. Can be indicated as gross savings and/or net savings values.

(49) **Rate class --** For the purpose of calculating EECRF rates, a utility's rate classes are those retail rate classes approved in the utility's most recent base-rate proceeding, excluding non-eligible customers.

(50) **Renewable demand side management (DSM) technologies --** Equipment that uses a renewable energy resource (renewable resource), as defined in §25.173(c) of this title (relating to Goal for Renewable Energy), a geothermal heat pump, a solar water heater, or another natural mechanism of the environment, that when installed at a customer site, reduces the customer's net purchases of energy, demand, or both.

(51) **Savings-to-Investment Ratio (SIR) --** The ratio of the present value of a customer's estimated lifetime electricity cost savings from energy efficiency measures to the present value of the installation costs, inclusive of any incidental repairs, of those energy efficiency measures.

(52) **Self-delivered program --** A program developed by a utility in an area in which customer choice is not offered that provides incentives directly to customers. The utility may use internal or external resources to design and administer the program.

(53) **Spillover --** Reductions in energy consumption and/or demand caused by the presence of an energy efficiency program, beyond the program-related gross savings of the participants and without financial or technical assistance from the program. There can be participant and/or non-participant spillover.

(54) **Spillover rate --** Estimate of energy savings attributable to spillover expressed as a percent of savings installed by participants through an energy efficiency program.

(55) **Standard offer contract --** A contract between an energy efficiency service provider and a participating utility or between a participating utility and a commercial customer specifying standard payments based upon the amount of energy and peak demand savings achieved through energy efficiency measures, the measurement and verification protocols, and other terms and conditions, consistent with this section.

(56) **Standard offer program --** A program under which a utility administers standard offer contracts between the utility and energy efficiency service providers.

(57) **Technical reference manual (TRM) --** A resource document compiled by the commission's EM&V contractor that includes information used in program planning and reporting of energy efficiency programs. It can include savings values for measures, engineering algorithms to calculate savings, impact factors to be applied to calculated savings (e.g., net-to-gross values), protocols, source documentation, specified assumptions, and other relevant material to support the calculation of measure and program savings.

(58) **Verification --** An independent assessment that a program has been implemented in accordance with the program design. The objectives of measure installation verification are to confirm the installation rate, that the installation meets reasonable quality standards, and that the measures are operating correctly and have the potential to generate the predicted savings. Verification activities are generally conducted during on-site surveys of a sample of projects. Project site inspections, participant phone and mail surveys and/or implementer and participant documentation review are typical activities associated with verification. Verification is also a subset of evaluation.

(d) **Cost-effectiveness standard**. An energy efficiency program is deemed to be cost-effective if the cost of the program to the utility is less than or equal to the benefits of the program. Utilities are encouraged to achieve demand reduction and energy savings through a portfolio of cost-effective programs that exceed each utility's energy efficiency goals while staying within the cost caps established in subsection (f)(7) of this section.

(1) The cost of a program includes the cost of incentives, measurement and verification, any shareholder bonus awarded to the utility, and actual or allocated research and development and administrative costs. The benefits of the program consist of the value of the demand reductions and energy savings, measured in accordance with the avoided costs prescribed in this subsection. The present value of the program benefits shall be calculated over the projected life of the measures installed or implemented under the program.

(2) The avoided cost of capacity is $80 per kW-year for all electric utilities through program year 2012, unless the commission establishes a different avoided cost of capacity in accordance with this paragraph. The avoided cost of capacity shall be revised beginning with program year 2013, in accordance with this paragraph.

(A) By November 15 of each year, commission staff shall post a notice of a revised avoided cost of capacity on the commission's website, on a webpage designated for this purpose, effective for the next program year. If the avoided cost of capacity has not changed, staff shall post a notice that the avoided cost of capacity remains the same.

(i) Staff shall calculate the avoided cost of capacity from the base overnight cost using the lower of a new conventional combustion turbine or a new advanced combustion turbine, as reported by the United States Department of Energy's Energy Information Administration's (EIA) Cost and Performance Characteristics of New Central Station Electricity Generating Technologies associated with EIA's Annual Energy Outlook. If EIA cost data that reflects current conditions in the industry does not exist, staff may establish an avoided cost of capacity using another data source.

(ii) If the EIA base overnight cost of a new conventional or an advanced combustion turbine, whichever is lower, is less than $700 per kW, the avoided cost of capacity shall be $80 per kW. If the base overnight cost of a new conventional or advanced combustion turbine, whichever is lower, is at or between $700 and $1,000 per kW, the avoided cost of capacity shall be $100 per kW. If the base overnight cost of a new conventional or advanced combustion turbine, whichever is lower, is greater than $1,000 per kW, the avoided cost of capacity shall be $120 per kW.

(iii) The avoided cost of capacity calculated by staff may be challenged only by the filing of a petition within 45 days of the date the avoided cost of capacity is posted on the commission's website on a webpage designated for that purpose.

(B) A utility in an area in which customer choice is not offered may petition the commission for authorization to use an avoided cost of capacity different from the avoided cost determined according to subparagraph (A) of this paragraph by filing a petition no later than 45 days after the date the avoided cost of capacity calculated by staff is posted on the commission's website on a webpage designated for that purpose. The avoided cost of capacity proposed by the utility shall be based on a generating resource or purchase in the utility's resource acquisition plan and the terms of the purchase or the cost of the resource shall be disclosed in the filing.

(3) The avoided cost of energy is $0.064 per kWh for all electric utilities through program year 2012, unless the commission establishes a different avoided cost of energy in accordance with this paragraph. The avoided cost of energy shall be revised beginning with program year 2013, in accordance with this paragraph.

(A) Commission staff shall post a notice of a revised avoided cost of energy by November 15 of each year on the commission's website, on a webpage designated for this purpose, effective for the next program year. If the cost of energy has not changed, staff shall post a notice that the cost of energy remains the same. By November 1 of each year, ERCOT shall calculate the avoided cost of energy for the ERCOT region, as defined in §25.5(48) of this title (relating to Definitions), by determining the load-weighted average of the competitive load zone settlement point prices for the peak periods covering the two previous winter and summer peaks.

(B) A utility in an area in which customer choice is not offered may petition the commission for authorization to use an avoided cost of energy other than that otherwise determined according to this paragraph. The avoided cost of energy may be based on peak period energy prices in an energy market operated by a regional transmission organization if the utility participates in that market and the prices are reported publicly. If the utility does not participate in such a market, the avoided cost of energy may be based on the expected heat rate of the gas-turbine generating technology specified in this subsection, multiplied by a publicly reported cost of natural gas.

(e) **Annual energy efficiency goals**.

(1) An electric utility shall administer a portfolio of energy efficiency programs to acquire, at a minimum, the following:

(A) The utility shall acquire no less than a 25% reduction of the electric utility's annual growth in demand of residential and commercial customers for the 2012 program year.

(B) Beginning with the 2013 program year, until the trigger described in subparagraph (C) of this paragraph is reached, the utility shall acquire a 30% reduction of its annual growth in demand of residential and commercial customers.

(C) If the demand reduction goal to be acquired by a utility under subparagraph (B) of this paragraph is equivalent to at least four-tenths of 1 % its summer weather-adjusted peak demand for the combined residential and commercial customers for the previous program year, the utility shall meet the energy efficiency goal described in subparagraph (D) of this paragraph for each subsequent program year.

(D) Once the trigger described in subparagraph (C) of this paragraph is reached, the utility shall acquire four-tenths of 1% of its summer weather-adjusted peak demand for the combined residential and commercial customers for the previous program year.

(E) Except as adjusted in accordance with subsection (w) of this section, a utility's demand reduction goal in any year shall not be lower than its goal for the prior year, unless the commission establishes a goal for a utility pursuant to paragraph (2) of this subsection.

(2) The commission may establish for a utility a lower goal than the goal specified in paragraph (1) of this subsection, a higher administrative spending cap than the cap specified under subsection (i) of this section, or an EECRF greater than the cap specified in subsection (f)(7) of this section if the utility demonstrates that compliance with that goal, administrative spending cap, or EECRF cost cap is not reasonably possible and that good cause supports the lower goal, higher administrative spending cap, or higher EECRF cost cap. To be eligible for a lower goal, higher administrative spending cap, or a higher EECRF cost cap, the utility must request a good cause exception as part of its EECRF application. If approved, the good cause exception is limited to the program year associated with the EECRF application.

(3) Each utility's demand-reduction goal shall be calculated as follows:

(A) Each year's historical demand for residential and commercial customers shall be adjusted for weather fluctuations, using weather data for the most recent ten years. The utility's growth in residential and commercial demand is based on the average growth in retail load in the Texas portion of the utility's service area, measured at the utility's annual system peak. The utility shall calculate the average growth rate for the prior five years.

(B) The demand goal for energy-efficiency savings for a year pursuant to paragraphs (1)(A) or (B) of this subsection is calculated by applying the percentage goal to the average growth in demand, calculated in accordance with subparagraph (A) of this paragraph. The annual demand goal for energy efficiency savings pursuant to paragraph (1)(D) of this subsection is calculated by applying the percentage goal to the utility's summer weather-adjusted five-year average peak demand for the combined residential and commercial customers.

(C) A utility may submit for commission approval an alternative method to calculate its growth in demand, for good cause.

(D) If a utility's prior five-year average load growth, calculated pursuant to subparagraph (A) of this paragraph, is negative, the utility shall use the demand reduction goal calculated using the alternative method approved by the commission beginning with the 2013 program year or, if the commission has not approved an alternative method, the utility shall use the previous year's demand reduction goal.

(E) A utility shall not claim savings obtained from energy efficiency measures funded through settlement orders or count towards the bonus calculation any savings obtained from grant incentives that have been awarded directly to the utility for energy efficiency programs.

(F) Savings achieved through programs for hard-to-reach customers shall be no less than 5.0% of the utility's total demand reduction goal.

(G) Utilities may apply peak savings on a per project basis to summer or winter peak, but not to both summer and winter peaks.

(4) An electric utility shall administer a portfolio of energy efficiency programs designed to meet an energy savings goal calculated from its demand savings goal, using a 20% conservation load factor.

(5) Electric utilities shall administer a portfolio of energy efficiency programs to effectively and efficiently achieve the goals set out in this section.

(A) Incentive payments may be made under standard offer contracts, market transformation contracts, or as part of a self-delivered program for energy savings and demand reductions. Each electric utility shall establish standard incentive payments to achieve the objectives of this section.

(B) Projects or measures under a standard offer, market transformation, or self-delivered program are not eligible for incentive payments or compensation if:

(i) A project would achieve demand or energy reduction by eliminating an existing function, shutting down a facility or operation, or would result in building vacancies or the re-location of existing operations to a location outside of the area served by the utility conducting the program, except for an appliance recycling program consistent with this section.

(ii) A measure would be adopted even in the absence of the energy efficiency service provider's proposed energy efficiency project, except in special cases, such as hard-to-reach and weatherization programs, or where free riders are accounted for using a net to gross adjustment of the avoided costs, or another method that achieves the same result. A project results in negative environmental or health effects, including effects that result from improper disposal of equipment and materials.

(C) Ineligibility pursuant to subparagraph (B) of this paragraph does not apply to standard offer, market transformation, and self-delivered programs aimed at energy code adoption, implementation, compliance, and enforcement under subsection (m) of this section, nor does it preclude standard offer, market transformation, or self-delivered programs promoting energy efficiency measures also required by energy codes to the degree such codes do not achieve full compliance rates.

(D) A utility in an area in which customer choice is not offered may achieve the goals of paragraphs (1) and (2) of this subsection by:

(i) providing rebate or incentive funds directly to eligible residential and commercial customers for programs implemented under this section; or

(ii) developing, subject to commission approval, new programs other than standard offer programs and market transformation programs, to the extent that the new programs satisfy the same cost-effectiveness standard as standard offer programs and market transformation programs using the process outlined in subsection (s) of this section.

(E) For a utility in an area in which customer choice is offered, the utility may achieve the goal of this section in rural areas by providing rebate or incentive funds directly to customers after demonstrating to the commission in a contested case hearing that the goal requirement cannot be met through the implementation of programs by retail electric providers or energy efficiency service providers in the rural areas.

(f) **Cost recovery**. A utility shall establish an energy efficiency cost recovery factor (EECRF) that complies with this subsection to timely recover the reasonable costs of providing a portfolio of cost-effective energy efficiency programs pursuant to this section.

(1) The EECRF shall be calculated to recover:

(A) For a utility that does not collect any amount of energy efficiency costs in its base rates, the utility's forecasted annual energy efficiency program expenditures, the preceding year's over- or under-recovery that includes municipal and utility EECRF proceeding expenses, any performance bonus earned under subsection (h) of this section, and EM&V costs allocated to the utility by the commission.

(B) For a utility that collects any amount of energy efficiency in its base rates, the utility's forecasted annual energy efficiency program expenditures in excess of the actual energy efficiency revenues collected from base rates as described in paragraph (2) of this subsection, the preceding year's over- or under-recovery that includes municipal and utility EECRF proceeding expenses, any performance bonus earned under subsection (h) of this section, and EM&V costs allocated to the utility by the commission.

(2) The commission may approve an EECRF for each eligible rate class. The costs shall be directly assigned to each rate class that receives services under the programs to the maximum extent reasonably possible. In its EECRF proceeding, a utility may request a good cause exception to combine one or more rate classes, each containing fewer than 20 customers, with a similar rate class that receives services under the same energy efficiency programs. For each rate class, the under- or over-recovery of the energy efficiency costs shall be the difference between actual EECRF revenues and actual costs for that class that comply with paragraph (12) of this subsection. Where a utility collects energy efficiency costs in its base rates, actual energy efficiency revenues collected from base rates consist of the amount of energy efficiency costs expressly included in base rates, adjusted to account for changes in billing determinants from the test year billing determinants used to set rates in the last base rate proceeding.

(3) A proceeding conducted pursuant to this subsection is a ratemaking proceeding for purposes of PURA §33.023. EECRF proceeding expenses shall be included in the EECRF calculated pursuant to paragraph (1) of this subsection as follows:

(A) For a utility's EECRF proceeding expenses, the utility may include only its expenses for the immediately previous EECRF proceeding conducted under this subsection.

(B) For municipalities' EECRF proceeding expenses, the utility may include only expenses paid or owed for the immediately previous EECRF proceeding conducted under this subsection for services reimbursable under PURA §33.023(b).

(4) Base rates shall not be set to recover energy efficiency costs.

(5) If a utility recovers energy efficiency costs through base rates, the EECRF may be changed in a general rate proceeding. If a utility is not recovering energy efficiency costs through base rates, the EECRF may be adjusted only in an EECRF proceeding pursuant to this subsection.

(6) For residential customers and for commercial rate classes whose base rates do not provide for demand charges, the EECRF rates shall be designed to provide only for energy charges. For commercial rate classes whose base rates provide for demand charges, the EECRF rates shall provide for energy charges or demand charges but not both. Any EECRF demand charge shall not be billed using a demand ratchet mechanism.

(7) The total EECRF costs outlined in paragraph (1) of this subsection, excluding EM&V costs and municipal EECRF proceeding expenses shall not exceed the amounts prescribed in this paragraph unless a good cause exception filed pursuant to subsection (e)(2) of this section is granted.

(A) For residential customers for program years 2016 and 2017, $0.001266 per kWh; and

(B) For residential customers for program year 2018, $0.001263 per kWh increased or decreased by a rate equal to the 2016 calendar year's percentage change in the South urban consumer price index (CPI), as determined by the Federal Bureau of Labor Statistics;

(C) For commercial customers for program years 2016 and 2017, rates designed to recover revenues equal to $0.000791 per kWh times the aggregate of all eligible commercial customers' kWh consumption; and

(D) For commercial customers for program year 2018, rates designed to recover revenues equal to $0.000790 per kWh increased or decreased by a rate equal to the 2016 calendar year's percentage change in the South urban CPI, as determined by the Federal Bureau of Labor Statistics times the aggregate of all eligible commercial customers' kWh consumption.

(E) For the 2019 program year and thereafter, the residential and commercial cost caps shall be calculated to be the prior period's cost caps increased or decreased by a rate equal to the most recently available calendar year's percentage change in the South urban CPI, as determined by the Federal Bureau of Labor Statistics.

(8) Not later than May 1 of each year, a utility in an area in which customer choice is not offered shall apply to adjust its EECRF effective January 1 of the following year. Not later than June 1 of each year, a utility in an area in which customer choice is offered shall apply to adjust its EECRF

effective March 1 of the following year. If a utility is in an area in which customer choice is offered in some but not all parts of its service area and files one energy efficiency plan and report covering all of its service area, the utility shall apply to adjust the EECRF not later than May 1 of each year, with the EECRF effective January 1 in the parts of its service area in which customer choice is not offered and March 1 in the parts of its service area in which customer choice is offered.

(9) Upon a utility's filing of an application to establish a new EECRF or adjust an EECRF, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding required by subparagraphs (A), (B), and (C) of this paragraph as follows:

(A) For a utility in an area in which customer choice is not offered, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding prior to the January 1 effective date of the new or adjusted EECRF, except where good cause supports a different procedural schedule.

(B) For a utility in an area in which customer choice is offered, the effective date of a new or adjusted EECRF shall be March 1. The presiding officer shall set a procedural schedule that will enable the utility to file an EECRF compliance tariff consistent with the final order within 10 days of the date of the final order. The procedural schedule shall also provide that the compliance filing date will be at least 45 days before the effective date of March 1. In no event shall the effective date of any new or adjusted EECRF occur less than 45 days after the utility files a compliance tariff consistent with a final order approving the new or adjusted EECRF. The utility shall service notice of the approved rates and the effective date of the approved rates by the working day after the utility files a compliance tariff consistent with the final order approving the new or adjusted EECRF to retail electric providers that are authorized by the registration agent to provide service in the utility's service area. Notice under this subparagraph may be served by email. The procedural schedule may be extended for good cause, but in no event shall the effective date of any new or adjusted EECRF occur less than 45 days after the utility files a compliance tariff consistent with a final order approving the new or adjusted EECRF, and in no event shall the utility serve notice of the approved rates and the effective date of the approved rates to retail electric providers that are authorized by the registration agent to provide service in the utility's service area more than one working day after the utility files the compliance tariff.

(C) For a utility in an area in which customer choice is offered in some but not all parts of its service area and that files one energy efficiency plan and report covering all of its service area, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding prior to the January 1 effective date of the new or adjusted EECRF for the areas in which customer choice is not offered, except where good cause supports a different schedule. For areas in which customer choice is offered, the effective date of the new or adjusted EECRF shall be March 1. The presiding officer shall set a procedural schedule that will enable the utility to file an EECRF compliance tariff consistent with the final order within 10 days of the date of the final order. The procedural schedule shall also provide that the compliance filing date will be at least 45 days before the effective date of March 1. In no event shall the effective date of any new or adjusted EECRF occur less than 45 days after the utility files a compliance tariff consistent with a final order approving the new or adjusted EECRF. The utility shall serve notice of the approved rates and the effective date of the approved rates by the working day after the utility files a compliance tariff consistent with the final order approving the new or adjusted EECRF to retail electric providers that are authorized by the registration agent to provide service in the utility's service area. Notice under this subparagraph of this paragraph may be served by email. The procedural schedule may be extended for good cause, but in no event shall the effective date of any new or adjusted

EECRF occur less than 45 days after the utility files a compliance tariff consistent with a final order approving the new or adjusted EECRF, and in no event shall the utility serve notice of the approved rates and the effective date of the approved rates to retail electric providers that are authorized by the registration agent to provide service in the utility's service area more than one working day after the utility files the compliance tariff.

(D) If no hearing is requested within 30 days of the filing of the application, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding within 90 days after a sufficient application was filed; or

(E) If a hearing is requested within 30 days of the filing of the application, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding within 180 days after a sufficient application was filed. If a hearing is requested, the hearing will be held no earlier than the first working day after the 45th day after a sufficient application is filed.

(10) A utility's application to establish or adjust an EECRF shall include testimony and schedules, in Excel format with formulas intact, showing the following, by retail rate class, for the prior program year and the program year for which the proposed EECRF will be collected as appropriate:

(A) the utility's forecasted energy efficiency costs;

(B) the actual base rate recovery of energy efficiency costs, adjusted for load changes in load subsequent to the last base rate proceeding, with supporting calculations;

(C) the energy efficiency performance bonus amount that it calculates to have earned for the prior year;

(D) any adjustment for past over- or under-recovery of energy efficiency revenues;

(E) information concerning the calculation of billing determinants for the most recent year and for the year in which the EECRF is expected to be in effect;

(F) the direct assignment and allocation of energy efficiency costs to the utility's eligible rate classes, including any portion of energy efficiency costs included in base rates, provided that the utility's actual EECRF expenditures by rate class may deviate from the projected expenditures by rate class, to the extent doing so does not exceed the cost caps in paragraph (7) of this subsection;

(G) information concerning calculations related to the requirements of paragraph (7) of this subsection;

(H) the incentive payments by the utility, by program, including a list of each energy efficiency administrator and/or service provider receiving more than 5% of the utility's overall incentive payments and the percentage of the utility's incentives received by those providers. Such information may be treated as confidential;

(I) the utility's administrative costs, including any affiliate costs and EECRF proceeding expenses and an explanation of both;

(J) the actual EECRF revenues by rate class for any period for which the utility calculates an under- or over-recovery of EECRF costs;

(K) the utility's bidding and engagement process for contracting with energy efficiency service providers, including a list of all energy efficiency service providers that participated in the utility programs and contractors paid with funds collected through the EECRF. Such information may be treated as confidential;

(L) the estimated useful life used for each measure in each program, or a link to the information if publicly available; and

(M) any other information that supports the determination of the EECRF.

(11) The following factors must be included in the application, as applicable, to support the recovery of energy efficiency costs under this subsection.

(A) the costs are less than or equal to the benefits of the programs, as calculated in subsection (d) of this section;

(B) the program portfolio was implemented in accordance with recommendations made by the commission's EM&V contractor and approved by the commission and the EM&V contractor has found no material deficiencies in the utility's administration of its portfolio of energy efficiency programs. This subparagraph does not preclude parties from examining and challenging the reasonableness of a utility's energy efficiency program expenses nor does it limit the commission's ability to address the reasonableness of a utility's energy efficiency program expenses;

(C) if a utility is in an area in which customer choice is offered and is subject to the requirements of PURA §39.905(f), the utility met its targeted low-income energy efficiency requirements;

(D) existing market conditions in the utility's service territory affected its ability to implement one or more of its energy efficiency programs or affected its costs;

(E) the utility's costs incurred and achievements accomplished in the previous year or estimated for the year the requested EECRF will be in effect are consistent with the utility's energy efficiency program costs and achievements in previous years notwithstanding any recommendations or comments by the EM&V contractor;

(F) changed circumstances in the utility's service area since the commission approved the utility's budget for the implementation year that affect the ability of the utility to implement any of its energy efficiency programs or its energy efficiency costs;

(G) the number of energy efficiency service providers operating in the utility's service territory affects the ability of the utility to implement any of its energy efficiency programs or its energy efficiency costs;

(H) customer participation in the utility's prior years' energy efficiency programs affects customer participation in the utility's energy efficiency programs in previous years or its proposed programs underlying its EECRF request and the extent to which program costs were expended to generate more participation or transform the market for the utility's programs;

(I) the utility's energy efficiency costs for the previous year or estimated for the year the requested EECRF will be in effect are comparable to costs in other markets with similar conditions; or

(J) the utility has set its incentive payments with the objective of achieving its energy and demand goals at the lowest reasonable cost per program.

(12) The scope of an EECRF proceeding includes the extent to which the costs recovered through the EECRF complied with PURA §39.905 and this section, and the extent to which the costs recovered were reasonable and necessary to reduce demand and energy growth. The proceeding shall not include a review of program design to the extent that the programs complied with the energy efficiency implementation project (EEIP) process defined in subsection (s) of this section. The commission shall not allow recovery of expenses that are designated as non-recoverable under §25.231(b)(2) of this title (relating to Cost of Service). In addition, the order shall contain findings of fact regarding the following:

(A) the costs to be recovered through the EECRF are reasonable estimates of the costs necessary to provide energy efficiency programs and to meet the utility's goals under this section;

(B) calculations of any under- or over-recovery of EECRF costs is consistent with this section;

(C) any energy efficiency performance bonus for which recovery is being sought is consistent with this section;

(D) the costs assigned or allocated to rate classes are reasonable and consistent with this section;

(E) the estimate of billing determinants for the period for which the EECRF is to be in effect is reasonable;

(F) any calculations or estimates of system losses and line losses used in calculating the charges are reasonable;

(G) whether the proposed EECRF rates comply with the requirements of paragraph (7) of this subsection; and

(H) whether the proposed EECRF rates comply with the requirements of subsection (r) of this section, if the utility is in an area in which customer choice is offered.

(13) Notice of a utility's filing of an EECRF application is reasonable if the utility provides in writing a general description of the application and the docket number assigned to the application within 7 days of the application filing date to:

(A) All parties in the utility's most recent completed EECRF docket;

(B) All retail electric providers that are authorized by the registration agent to provide service in the utility's service area at the time the EECRF application is filed;

(C) All parties in the utility's most recent completed base-rate proceeding; and

(D) The state agency that administers the federal weatherization program.

(14) The utility shall file an affidavit attesting to the completion of notice within 14 days after the application is filed.

(g) **Incentive payments**. The incentive payments for each customer class shall not exceed 100% of avoided cost, as determined in accordance with this section. The incentive payments shall be set by each utility with the objective of achieving its energy and demand savings goals at the lowest reasonable cost per program. Different incentive levels may be established for areas that have historically been underserved by the utility's energy efficiency programs or for other appropriate reasons. Utilities may adjust incentive payments during the program year, but such adjustments must be clearly publicized in the materials used by the utility to set out the program rules and describe the programs to participating energy efficiency service providers.

(h) **Energy efficiency performance bonus**. A utility that exceeds its demand and energy reduction goals established in this section at a cost that does not exceed the cost caps established in subsection (f)(7) of this section shall be awarded a performance bonus calculated in accordance with this subsection. The performance bonus shall be based on the utility's energy efficiency achievements for the previous program year. The bonus calculation shall not include demand or energy savings that result from programs other than programs implemented under this section.

(1) The performance bonus shall entitle the utility to receive a share of the net benefits realized in meeting its demand reduction goal established in this section.

(2) Net benefits shall be calculated as the sum of total avoided cost associated with the eligible programs administered by the utility minus the sum of all program costs. Total avoided costs and program costs shall be calculated in accordance with this section.

(3) Beginning with the 2012 program year, a utility that exceeds 100% of its demand and energy reduction goals shall receive a bonus equal to 1% of the net benefits for every 2% that the demand reduction goal has been exceeded, with a maximum of 10% of the utility's total net benefits.

(4) The commission may reduce the bonus otherwise permitted under this subsection for a utility with a lower goal, higher administrative spending cap, or higher EECRF cost cap established by the commission pursuant to subsection (e)(2) of this section. The bonus shall be considered in the EECRF proceeding in which the bonus is requested.

(5) In calculating net benefits to determine a performance bonus, a discount rate equal to the utility's weighted average cost of capital of the utility and an escalation rate of 2 % shall be used. The utility shall provide documentation for the net benefits calculation, including, but not limited to, the weighted average cost of capital, useful life of equipment or measure, and quantity of each measure implemented.

(6) The bonus shall be allocated in proportion to the program costs associated with meeting the demand and energy goals and allocated to eligible customers on a rate class basis.

(7) A bonus earned under this section shall not be included in the utility's revenues or net income for the purpose of establishing a utility's rates or commission assessment of its earnings.

(i) **Utility administration**. The cost of administration shall not exceed 15% of a utility's total program costs. The cost of research and development shall not exceed 10% of a utility's total program costs for the previous program year. The cumulative cost of administration and research and development shall not exceed 20% of a utility's total program costs, unless a good cause exception filed pursuant to subsection (e)(2) of this section is granted. Any portion of these costs which are not directly assignable to a specific program shall be allocated among the programs in proportion to the program incentive costs. Any bonus awarded by the commission shall not be included in program costs for the purpose of applying these limits.

(1) Administrative costs include all reasonable and necessary costs incurred by a utility in carrying out its responsibilities under this section, including:

(A) conducting informational activities designed to explain the standard offer programs and market transformation programs to energy efficiency service providers, retail electric providers, and vendors;

(B) for a utility offering self-delivered programs, internal utility costs to conduct outreach activities to customers and energy efficiency service providers will be considered administration;

(C) providing informational programs to improve customer awareness of energy efficiency programs and measures;

(D) reviewing and selecting energy efficiency programs in accordance with this section;

(E) providing regular and special reports to the commission, including reports of energy and demand savings;

(F) a utility's costs for an EECRF proceeding conducted pursuant to subsection (f) of this section;

(G) the costs paid by a utility pursuant to PURA §33.023(b) for an EECRF proceeding conducted pursuant to subsection (f) of this section; however, these costs are not included in the administrative caps applied in this paragraph; and

(H) any other activities that are necessary and appropriate for successful program implementation.

(2) A utility shall adopt measures to foster competition among energy efficiency service providers for standard offer, market transformation, and self-delivered programs, such as limiting the number of projects or level of incentives that a single energy efficiency service provider and its affiliates is eligible for and establishing funding set-asides for small projects.

(3) A utility may establish funding set-asides or other program rules to foster participation in energy efficiency programs by municipalities and other governmental entities.

(4) Electric utilities offering standard offer, market transformation, and self-delivered programs shall use standardized forms, procedures, deemed savings estimates and program templates. The electric utility shall file any standardized materials, or any change to it, with the commission at least 60 days prior to its use. In filing such materials, the utility shall provide an explanation of changes from the version of the materials that was previously used. For standard offer, market transformation, and self-delivered programs, the utility shall provide relevant documents to REPs and EESPs and work collaboratively with them when it changes program documents, to the extent that such changes are not considered in the energy efficiency implementation project described in subsection (s) of this section.

(5) Each electric utility in an area in which customer choice is offered shall conduct programs to encourage and facilitate the participation of retail electric providers and energy efficiency service providers in the delivery of efficiency and demand response programs, including:

(A) Coordinating program rules, contracts, and incentives to facilitate the statewide marketing and delivery of the same or similar programs by retail electric providers;

(B) Setting aside amounts for programs to be delivered to customers by retail electric providers and establishing program rules and schedules that will give retail electric providers sufficient time to plan, advertise, and conduct energy efficiency programs, while preserving the utility's ability to meet the goals in this section; and

(C) Working with retail electric providers and energy efficiency service providers to evaluate the demand reductions and energy savings resulting from time-of-use prices, home-area network devices, such as in home displays, and other programs facilitated by advanced meters to determine the demand and energy savings from such programs.

(j) **Standard offer programs**. A utility's standard offer program shall be implemented through program rules and standard offer contracts that are consistent with this section. Standard offer contracts will be available to any energy efficiency service provider that satisfies the contract requirements prescribed by the utility under this section and demonstrates that it is capable of managing energy efficiency projects under an electric utility's energy efficiency program.

(k) **Market transformation programs**. Market transformation programs are strategic efforts, including, but not limited to, incentives and education designed to reduce market barriers for energy efficient technologies and practices. Market transformation programs may be designed to obtain energy savings or peak demand reductions beyond savings that are reasonably expected to be achieved as a result of current compliance levels with existing building codes applicable to new buildings and equipment efficiency standards or standard offer programs. Market transformation programs may also be specifically designed to express support for early adoption, implementation, and enforcement of the most recent version of the International Energy Conservation Code for residential or commercial buildings by local jurisdictions, express support for more effective implementation and enforcement of the state energy code and compliance with the state energy code, and encourage utilization of the types of building components, products, and services required to comply with such energy codes. The existence of federal, state, or local governmental funding for, or encouragement to utilize, the types of building components, products, and services required to comply with such energy codes does not prevent utilities from offering programs to supplement governmental spending and encouragement. Utilities should cooperate with the REPs, and, where possible, leverage existing industry-recognized programs that have the potential to reduce demand and energy consumption in Texas and consider statewide administration where appropriate. Market transformation programs may operate over a period of more than one year and may demonstrate cost-effectiveness over a period longer than one year.

(l) **Self-delivered programs**. A utility may use internal or external resources to design, administer, and deliver self-delivered programs. The programs shall be tailored to the unique characteristics of the utility's service area in order to attract customer and energy efficiency service provider participation. The programs shall meet the same cost effectiveness requirements as standard offer and market transformation programs.

(m) **Requirements for standard offer, market transformation, and self-delivered programs**. A utility's standard offer, market transformation, and self-delivered programs shall meet the requirements of this subsection. A utility may conduct information and advertising campaigns to foster participation in standard offer, market transformation, and self-delivered programs.

(1) Standard offer, market transformation, and self-delivered programs:

(A) shall describe the eligible customer classes and allocate funding among the classes on an equitable basis;

(B) may offer standard incentive payments and specify a schedule of payments that are sufficient to meet the goals of the program, which shall be consistent with this section, or any revised payment formula adopted by the commission. The incentive payments may include both payments for energy and demand savings, as appropriate;

(C) shall not permit the provision of any product, service, pricing benefit, or alternative terms or conditions to be conditioned upon the purchase of any other good or service from the utility, except that only customers taking transmission and distribution services from a utility can participate in its energy efficiency programs;

(D) shall provide for a complaint process that allows:

(i) an energy efficiency service provider to file a complaint with the commission against a utility; and

(ii) a customer to file a complaint with the utility against an energy efficiency service provider;

(E) may permit the use of distributed renewable generation, geothermal, heat pump, solar water heater and combined heat and power technologies, involving installations of ten megawatts or less;

(F) may factor in the estimated level of enforcement and compliance with existing energy codes in determining energy and peak demand savings; and

(G) may require energy efficiency service providers to provide the following:

(i) a description of how the value of any incentive will be passed on to customers;

(ii) evidence of experience and good credit rating;

(iii) a list of references;

(iv) all applicable licenses required under state law and local building codes;

(v) evidence of all building permits required by governing jurisdictions; and

(vi) evidence of all necessary insurance.

(2) Standard offer and self-delivered programs:

(A) shall require energy efficiency service providers to identify peak demand and energy savings for each project in the proposals they submit to the utility;

(B) shall be neutral with respect to specific technologies, equipment, or fuels. Energy efficiency projects may lead to switching from electricity to another energy source, provided that the energy efficiency project results in overall lower energy costs, lower energy consumption, and the installation of high efficiency equipment. Utilities may not pay incentives for a customer to switch from gas appliances to electric appliances except in connection with the installation of high efficiency combined heating and air conditioning systems;

(C) shall require that all projects result in a reduction in purchased energy consumption, or peak demand, or a reduction in energy costs for the end-use customer;

(D) shall encourage comprehensive projects incorporating more than one energy efficiency measure;

(E) shall be limited to projects that result in consistent and predictable energy or peak demand savings over an appropriate period of time based on the life of the measure; and

(F) may permit a utility to use poor performance, including customer complaints, as a criterion to limit or disqualify an energy efficiency service provider or its affiliate from participating in a program.

(3) A market transformation program shall identify:

(A) program goals;

(B) market barriers the program is designed to overcome;

(C) key intervention strategies for overcoming those barriers;

(D) estimated costs and projected energy and capacity savings;

(E) a baseline study that is appropriate in time and geographic region. In establishing a baseline, the study shall consider the level of regional implementation and enforcement of any applicable energy code;

(F) program implementation timeline and milestones;

(G) a description of how the program will achieve the transition from extensive market intervention activities toward a largely self-sustaining market;

(H) a method for measuring and verifying savings; and

(I) the period over which savings shall be considered to accrue, including a projected date by which the market will be sufficiently transformed so that the program should be discontinued.

(4) A market transformation program shall be designed to achieve energy or peak demand savings, or both, and lasting changes in the way energy efficient goods or services are distributed, purchased, installed, or used over a defined period of time. A utility shall use fair competitive procedures to select EESPs to conduct a market transformation program, and shall include in its annual report the justification for the selection of an EESP to conduct a market transformation program on a sole-source basis.

(5) A load-control standard-offer program shall not permit an energy efficiency service provider to receive incentives under the program for the same demand reduction benefit for which it is compensated under a capacity-based demand response program conducted by an independent organization, independent system operator, or regional transmission operator. The qualified scheduling entity representing an energy efficiency service provider is not prohibited from receiving revenues from energy sold in ERCOT markets in addition to any incentive for demand reduction offered under a utility load-control standard offer program.

(6) Utilities offering load management programs shall work with ERCOT and energy efficiency service providers to identify eligible loads and shall integrate such loads into the ERCOT markets to the extent feasible. Such integration shall not preclude the continued operation of utility load management programs that cannot be feasibly integrated into the ERCOT markets or that continue to provide separate and distinct benefits.

(n) **Energy efficiency plans and reports (EEPR)**. Each electric utility shall file by April 1 of each year an energy efficiency plan and report in a project annually designated for this purpose, as described in this subsection. The plan and report shall be filed as a searchable pdf document.

(1) Each electric utility's energy efficiency plan and report shall describe how the utility intends to achieve the goals set forth in this section and comply with the other requirements of this section. The plan and report shall be based on program years. The plan and report shall propose an annual budget sufficient to reach the goals specified in this section.

(2) Each electric utility's plan and report shall include:

(A) the utility's total actual and weather-adjusted peak demand and actual and weather-adjusted peak demand for residential and commercial customers for the previous five years;

(B) the demand goal calculated in accordance with this section for the current year and the following year, including documentation of the demand, weather adjustments, and the calculation of the goal;

(C) the utility's customers' total actual and weather-adjusted energy consumption and actual and weather-adjusted energy consumption for residential and commercial customers for the previous five years;

(D) the energy goal calculated in accordance with this section, including documentation of the energy consumption, weather adjustments, and the calculation of the goal;

(E) a description of existing energy efficiency programs and an explanation of the extent to which these programs will be used to meet the utility's energy efficiency goals;

(F) a description of each of the utility's energy efficiency programs that were not included in the previous year's plan, including measurement and verification plans if appropriate, and any baseline studies and research reports or analyses supporting the value of the new programs;

(G) an estimate of the energy and peak demand savings to be obtained through each separate energy efficiency program;

(H) a description of the customer classes targeted by the utility's energy efficiency programs, specifying the size of the hard-to-reach, residential, and commercial classes, and the methodology used for estimating the size of each customer class;

(I) the proposed annual budget required to implement the utility's energy efficiency programs, broken out by program for each customer class, including hard-to-reach customers, and any set-asides or budget restrictions adopted or proposed in accordance with this section. The proposed budget shall detail the incentive payments and utility administrative costs, including specific items for research and information and outreach to energy efficiency service providers, and other major administrative costs, and the basis for estimating the proposed expenditures;

(J) a discussion of the types of informational activities the utility plans to use to encourage participation by customers, energy efficiency service providers, and retail electric providers to participate in energy efficiency programs, including the manner in which the utility will provide notice of energy efficiency programs, and any other facts that may be considered when evaluating a program;

(K) the utility's performance in achieving its energy goal and demand goal for the prior five years, as reported in annual energy efficiency reports filed in accordance with this section;

(L) a comparison of projected savings (energy and demand), reported savings, and verified savings for each of the utility's energy efficiency programs for the prior two years;

(M) a description of the results of any market transformation program, including a comparison of the baseline and actual results and any adjustments to the milestones for a market transformation program;

(N) a description of self-delivered programs;

(O) expenditures for the prior five years for energy and demand incentive payments and program administration, by program and customer class;

(P) funds that were committed but not spent during the prior year, by program;

(Q) a comparison of actual and budgeted program costs, including an explanation of any increase or decreases of more than 10% in the cost of a program;

(R) information relating to energy and demand savings achieved and the number of customers served by each program by customer class;

(S) the utility's most recent EECRF, the revenue collected through the EECRF, the utility's forecasted annual energy efficiency program expenditures in excess of the actual energy efficiency revenues collected from base rates as described in subsection (f)(2) of this section, and the control number under which the most recent EECRF was established;

(T) the amount of any over- or under-recovery energy efficiency program costs whether collected through base rates or the EECRF;

(U) a list of any counties that in the prior year were under-served by the energy efficiency program;

(V) a calculation showing whether the utility qualifies for a performance bonus and the amount of any bonus;

(W) a description of new or discontinued programs, including pilot programs that are planned to be continued as full programs. For programs that are to be introduced or pilot programs that are to be continued as full programs, the description shall include the budget and projected demand and energy savings; and

(X) a link to the program manuals for the current program year.

(o) **Review of programs**. Commission staff may initiate a proceeding to review a utility's energy efficiency programs. In addition, an interested entity may request that the commission initiate a proceeding to review a utility's energy efficiency programs.

(p) **Inspection, measurement and verification**. Each standard offer, market transformation, and self-delivered program shall include use of an industry - accepted evaluation and/or measurement and verification protocol, such as the International Performance Measurement and Verification Protocol (IPMVP) or a protocol approved by the commission, to document and verify energy and peak demand savings to ensure that the goals of this section are achieved. A utility shall not provide an energy efficiency service provider final compensation until the provider establishes that the work is complete and evaluation and/or measurement and verification in accordance with the protocol verifies that the savings will be achieved. However, a utility may provide an energy efficiency service provider that offers behavioral programs incremental compensation as work is performed. If inspection of one or more measures is a part of the protocol, a utility shall not provide an energy efficiency service provider final compensation until the utility has conducted its inspection on at least a sample of measures and the inspections confirm that the work has been done. A utility shall provide inspection reports to commission staff within 20 days of staff's request.

(1) The energy efficiency service provider, or for self-delivered programs the utility is responsible for the determination and documentation of energy and peak demand savings using the approved evaluation and/or measurement and verification protocol, and may utilize the services of an independent third party for such purposes.

(2) Commission-approved deemed energy and peak demand savings may be used in lieu of the energy efficiency service provider's measurement and verification, where applicable. The deemed savings approved by the commission before December 31, 2007 are continued in effect, unless superseded by commission action.

(3) Where installed measures are employed, an energy efficiency service provider shall verify that the measures contracted for were installed before final payment is made to the energy efficiency service provider, by obtaining the customer's signature certifying that the measures were installed, or by other reasonably reliable means approved by the utility.

(4) For projects involving over 30 installations, a statistically significant sample of installations will be subject to on-site inspection in accordance with the protocol for the project to verify that measures are installed and capable of performing their intended function. Inspection shall occur within 30 days of notification of measure installation.

(5) Projects of less than 30 installations may be aggregated and a statistically significant sample of the aggregate installations will be subject to on-site inspection in accordance with the protocol for the projects to ensure that measures are installed and capable of performing their intended function. Inspection shall occur within 30 days of notification of measure installation.

(6) Where installed measures are employed, the sample size for on-site inspections may be adjusted for an energy efficiency service provider under a particular contract, based on the results of prior inspections.

(q) **Evaluation, measurement, and verification (EM&V)**. The following defines the evaluation, measurement, and verification (EM&V) framework to be implemented starting in program year 2013. The goal of this framework is to ensure that the programs are evaluated, measured, and verified using a consistent process that allows for accurate estimation of energy and demand impacts.

(1) EM&V objectives include:

(A) Documenting the impacts of the utilities' individual energy efficiency and load management portfolios, comparing their performance with established goals, and determining cost-effectiveness;

(B) Providing feedback for the commission, commission staff, utilities, and other stakeholders on program portfolio performance; and

(C) Providing input into the utilities' and ERCOT's planning activities.

(2) The principles that guide the EM&V activities in meeting the primary EM&V objectives are:

(A) Evaluators follow ethical guidelines.

(B) Important and relevant assumptions used by program planners and administrators are reviewed as part of the EM&V efforts.

(C) All important and relevant EM&V assumptions and calculations are documented and the reliability of results is indicated in evaluation reports.

(D) The majority of evaluation expenditures and efforts are in areas of greatest importance or uncertainty.

(3) The commission shall select an entity to act as the commission's EM&V contractor and conduct evaluation activities. The EM&V contractor shall operate under the commission's supervision and oversight, and the EM&V contractor shall offer independent analysis to the commission in order to assist in making decisions in the public interest.

(A) Under the oversight of the commission staff and with the assistance of utilities and other parties, the EM&V contractor will evaluate specific programs and the portfolio of programs for each utility.

(B) The EM&V contractor shall have the authority to request data it considers necessary to fulfill its evaluation, measurements, and verification responsibilities from the utilities. A utility shall make good faith efforts to provide complete, accurate, and timely responses to all EM&V contractor requests for documents, data, information and other materials. The commission may on its own volition or upon recommendation by staff require that a utility provide the EM&V contractor with specific information.

(4) Evaluation activities will be conducted by the EM&V contractor, starting with activities associated with program year 2012, to meet the evaluation objectives defined in this section. Activities shall include, but are not limited to:

(A) Providing appropriate planning documents.

(B) Impact evaluations to determine and document appropriate metrics for each utility's individual evaluated programs and portfolio of all programs, annual portfolio evaluation reports, and additional reports and services as defined by commission staff to meet the EM&V objectives.

(C) Preparation of a statewide technical reference manual (TRM), including updates to such manual as defined in this subsection.

(5) The impact evaluation activities may include the use of one or more evaluation approaches. Evaluation activities may also include, or just include, verification activities on a census or sample of projects implemented by the utilities. Evaluations may also include the use of due-diligence on utility-provided documentation as well as surveys of program participants, non-participants, contractors, vendors, and other market actors.

(6) The following apply to the development of a statewide TRM by the EM&V contractor.

(A) The EM&V contractor shall use existing Texas, or other state, deemed savings manual(s), protocols, and the work papers used to develop the values in the manual(s), as a foundation for developing the TRM. The TRM shall include applicability requirements for each deemed savings value or deemed savings calculation. The TRM may also include standardized EM&V protocols for determining and/or verifying energy and demand savings for particular measures or programs. Utilities may apply TRM deemed savings values or deemed savings calculations to a measure or program if the applicability criteria are met.

(B) The TRM shall be reviewed by the EM&V contractor at least annually, pursuant to a schedule determined by commission staff, with the intention of preparing an updated TRM, if needed. In addition, any utility or other stakeholder may request additions to or modifications to the TRM at any time with the provision of documentation for the basis of such an addition or modification. At the discretion of commission staff, the EM&V contractor may review such documentation to prepare a recommendation with respect to the addition or modification.

(C) Commission staff shall approve the initial TRM and any updated TRMs. The approval process for any TRM additions or modifications, not made during the regular review schedule determined by commission staff, shall include a review by commission staff to determine if an addition or modification is appropriate before an annual update.

(D) Any changes to the TRM shall be applied prospectively to programs offered in the appropriate program year.

(E) The TRM shall be publicly available.

(F) Utilities may use their existing deemed savings values in their 2013 program year energy efficiency plan and report, submitted in 2012, if the TRM is not available. Starting with their 2014 program year energy efficiency plan and report, submitted in 2013, utilities shall utilize the values contained in the TRM, unless the commission indicates otherwise.

(7) The utilities shall prepare projected savings estimates and claimed savings estimates. The utilities shall conduct their own EM&V activities for purposes such as confirming any incentive payments to customers or contractors and preparing documentation for internal and external reporting, including providing documentation to the EM&V contractor. The EM&V contractor shall prepare evaluated savings for preparation of its evaluation reports and a realization rate comparing evaluated savings with projected savings estimates and/or claimed savings estimates.

(8) Baselines for preparation of TRM deemed savings values or deemed savings calculations or for other evaluation activities shall be defined by the EM&V contractor and commission staff shall review and approve them. When common practice baselines are defined for determining gross energy and/or demand savings for a measure or program, common practice may be documented by market studies. Baselines shall be defined by measure category as follows (deviations from these specifications may be made with justification and approval of commission staff):

(A) Baseline is existing conditions for the estimated remaining lifetime of existing equipment for early replacement of functional equipment still within its current useful life. Baseline is applicable code, standard or common practice for remaining lifetime of the measure past the estimated remaining lifetime of existing equipment;

(B) Baseline is applicable code, standard or common practice for replacement of functional equipment beyond its current useful life;

(C) Baseline is applicable code, standard or common practice for unplanned replacements of failed equipment; and

(D) Baseline is applicable code, standard or common practice for new construction or major tenant improvements.

(9) Relevant recommendations of the EM&V contractor related to program design and reporting should be addressed in the Energy Efficiency Implementation Project (EEIP) and considered for implementation in future program years. The commission may require a utility to implement the EM&V contractor's recommendations in a future program year.

(10) The utilities shall be assigned the EM&V costs in proportion to their annual program costs and shall pay the invoices approved by the commission. The 2013 and 2014 EM&V expenses outlined in the EM&V contractor's budget shall be recovered through the EECRFs approved by the commission in the EECRF proceedings initiated by the utilities in 2013. The commission shall at least biennially review the EM&V contractor's costs and establish a budget for its services sufficient to pay for those services that it determines are economic and beneficial to be performed.

(A) The funding of the EM&V contractor shall be sufficient to ensure the selection of an EM&V contractor in accordance with the scope of EM&V activities outlined in this subsection.

(B) EM&V costs shall be itemized in the utilities' annual reports to the commission as a separate line item. The EM&V costs shall not count against the utility's cost caps or administration spending caps.

(11) For the purpose of analysis, the utility shall grant the EM&V contractor access to data maintained in the utilities' data tracking systems, including, but not limited to, the following proprietary customer information: customer identifying information, individual customer contracts, and load and usage data in accordance with §25.272(g)(1)(A) of this title (relating to Code of Conduct for

Electric Utilities and Their Affiliates). Such information shall be treated as confidential information.

(A) The utility shall maintain records for three (3) years that include the date, time, and nature of proprietary customer information released to the EM&V contractor.

(B) The EM&V contractor shall aggregate data in such a way as to protect customer, retail electric provider, and energy efficiency service provider proprietary information in any non-confidential reports or filings the EM&V contractor prepares.

(C) The EM&V contractor shall not utilize data provided or received under commission authority for any purposes outside the authorized scope of work the EM&V contractor performs for the commission.

(D) The EM&V contractor providing services under this section shall not release any information it receives related to the work performed unless directed to do so by the commission.

(12) For evaluation of 2012 and 2013 program years' programs and portfolios, the EM&V contractor may implement a reduced level of EM&V activities as the EM&V contractor will not be retained by the commission until after the start of the 2012 program year. Should the EM&V contractor determine that deemed savings values utilized by the utilities for program years 2012 and/or 2013 are different than values the EM&V contractor develops for the TRM, the EM&V contractor shall report two sets of impacts - one with the TRM values and one with the utilities' values for 2012 and/or 2013 program years.

(r) **Targeted low income energy efficiency program**. Each unbundled transmission and distribution utility shall include in its energy efficiency plan a targeted low-income energy efficiency program. A utility in an area in which customer choice is not offered may include in its energy efficiency plan a targeted low-income energy efficiency program that utilizes the cost-effectiveness methodology provided in paragraph (2) of this subsection. Savings achieved by the program shall count toward the utility's energy efficiency goal.

(1) Each utility shall ensure that annual expenditures for the targeted low-income energy efficiency program are not less than 10% of the utility's energy efficiency budget for the program year.

(2) The utility's targeted low-income program shall incorporate a whole-house assessment that will evaluate all applicable energy efficiency measures for which there are commission-approved deemed savings. The cost-effectiveness of measures eligible to be installed and the overall program shall be evaluated using the Savings-to-Investment (SIR) ratio.

(3) Any funds that are not obligated after July of a program year may be made available for use in the hard-to-reach program.

(s) **Energy Efficiency Implementation Project - EEIP**. The commission shall use the EEIP to develop best practices in standard offer market transformation, self-directed, pilot, or other programs, modifications to programs, standardized forms and procedures, protocols, deemed savings estimates, program templates, and the overall direction of the energy efficiency program established by this section. Utilities shall provide timely responses to questions posed by other participants relevant to the tasks of the EEIP. Any recommendations from the EEIP process shall relate to future years as described in this subsection.

(1) The following functions may also be undertaken in the EEIP:

(A) development, discussion, and review of new statewide standard offer programs;

(B) identification, discussion, design, and review of new market transformation programs;

(C) determination of measures for which deemed savings are appropriate and participation in the development of deemed savings estimates for those measures;

(D) review of and recommendations on the commission EM&V contractor's reports;

(E) review of and recommendations on incentive payment levels and their adequacy to induce the desired level of participation by energy efficiency service providers and customers;

(F) review of and recommendations on a utility annual energy efficiency plans and reports;

(G) utility program portfolios and proposed energy efficiency spending levels for future program years;

(H) periodic reviews of the cost-effectiveness methodology; and

(I) other activities as identified by commission staff.

(2) The EEIP projects shall be conducted by commission staff. The commission's EM&V contractor's reports shall be filed in the project at a date determined by commission staff.

(3) A utility that intends to launch a program that is substantially different from other programs previously implemented by any utility affected by this section shall file a program template and shall provide notice of such to EEIP participants. Notice to EEIP participants need not be provided if a program description or program template for the new program is provided through the utility's annual energy efficiency report. Following the first year in which a program was implemented, the utility shall include the program results in the utility's annual energy efficiency report.

(4) Participants in the EEIP may submit comments and reply comments in the EEIP on dates established by commission staff.

(5) Any new programs or program redesigns shall be submitted to the commission in a petition in a separate proceeding. The approved changes shall be available for use in the utilities' next EEPR and EECRF filings. If the changes are not approved by the commission by November 1 in a particular year, the first time that the changes shall be available for use is the second EEPR and EECRF filings made after commission approval.

(6) Any interested entity that participates in the EEIP may file a petition to the commission for consideration regarding changes to programs.

(t) **Retail providers**. Each utility in an area in which customer choice is offered shall conduct outreach and information programs and otherwise use its best efforts to encourage and facilitate the involvement of retail electric providers as energy efficiency service companies in the delivery of efficiency and demand response programs.

(u) **Customer protection**. Each energy efficiency service provider that provides energy efficiency services to end-use customers under this section shall provide the disclosures and include the contractual provisions required by this subsection, except for commercial customers with a peak load exceeding 50 kW. Paragraph (1) of this subsection does not apply to behavioral energy efficiency programs that do not require a contract with a customer.

(1) Clear disclosure to the customer shall be made of the following:

(A) the customer's right to a cooling-off period of three business days, in which the contract may be canceled, if applicable under law;

(B) the name, telephone number, and street address of the energy efficiency services provider and any subcontractor that will be performing services at the customer's home or business;

(C) the fact that incentives are made available to the energy efficiency services provider through a program funded by utility customers, manufacturers or other entities and the amount of any incentives provided by the utility;

(D) the amount of any incentives that will be provided to the customer;

(E) notice of provisions that will be included in the customer's contract, including warranties;

(F) the fact that the energy efficiency service provider must measure and report to the utility the energy and peak demand savings from installed energy efficiency measures;

(G) the liability insurance to cover property damage carried by the energy efficiency service provider and any subcontractor;

(H) the financial arrangement between the energy efficiency service provider and customer, including an explanation of the total customer payments, the total expected interest charged, all possible penalties for non-payment, and whether the customer's installment sales agreement may be sold;

(I) the fact that the energy efficiency service provider is not part of or endorsed by the commission or the utility; and

(J) a description of the complaint procedure established by the utility under this section, and toll free numbers for the Office of Customer Protection of the Public Utility Commission of Texas, and the Office of Attorney General's Consumer Protection Hotline.

(2) The energy efficiency service provider's contract with the customer, where such a contract is employed, shall include:

(A) work activities, completion dates, and the terms and conditions that protect residential customers in the event of non-performance by the energy efficiency service provider;

(B) provisions prohibiting the waiver of consumer protection statutes, performance warranties, false claims of energy savings and reductions in energy costs;

(C) a disclosure notifying the customer that consumption data may be disclosed to the EM&V contractor for evaluation purposes; and

(D) a complaint procedure to address performance issues by the energy efficiency service provider or a subcontractor.

(3) When an energy efficiency service provider completes the installation of measures for a customer, it shall provide the customer an "All Bills Paid" affidavit to protect against claims of subcontractors.

(v) **Grandfathered programs**. An electric utility that offered a load management standard offer program for industrial customers prior to May 1, 2007 shall continue to make the program available, at 2007 funding and participation levels, and may include additional customers in the program to maintain these funding and participation levels.

(w) **Identification notice.** An industrial customer taking electric service at distribution voltage may submit a notice identifying the distribution accounts for which it qualifies under subsection (c)(30) of this section. The identification notice shall be submitted directly to the customer's utility. An identification notice submitted under this section must be renewed every three years. Each identification notice must include the name of the industrial customer, a copy of the customer's Texas Sales and Use Tax Exemption Certification (pursuant to Tax Code §151.317), a description of the industrial process taking place at the consuming facilities, and the customer's applicable account number(s) or ESID number(s). The identification notice is limited solely to the metered point of delivery of the industrial process taking place at the consuming facilities. The account number(s) or ESID number(s) identified by the industrial customer under this section shall not be charged for any costs associated with programs provided under this section, including any shareholder bonus awarded; nor shall the identified facilities be eligible to participate in utility-administered energy efficiency programs during the term. Beginning with the 2013 program year, notices shall be submitted not later than February 1 to be effective for the following program year. A utility's demand reduction goal shall be adjusted to remove any load that is lost as a result of this subsection.

(x) **Administrative penalty**. The commission may impose an administrative penalty or other sanction if the utility fails to meet a goal for energy efficiency under this section. Factors, to the extent they are outside of the utility's control, that may be considered in determining whether to impose a sanction for the utility's failure to meet the goal include:

(1) the level of demand by retail electric providers and energy efficiency service providers for program incentive funds made available by the utility through its programs;

(2) changes in building energy codes; and

(3) changes in government-imposed appliance or equipment efficiency standards.

§25.183. Reporting and Evaluation of Energy Efficiency Programs.

(a) **Purpose.** The purpose of this section is to establish reporting requirements sufficient for the commission, in cooperation with Energy Systems Laboratory of Texas A&M University (Laboratory), to quantify, by county, the reductions in energy consumption, peak demand and associated emissions of air contaminants achieved from the programs implemented under §25.181 of this title (relating to the Energy Efficiency Goal) and §25.182 of this title (relating to Energy Efficiency Grant Program).

(b) **Application.** This section applies to electric utilities administering energy efficiency programs implemented under the Public Utility Regulatory Act (PURA) §39.905 and pursuant to §25.181 of this title, and grantees administering energy efficiency grants implemented under Health and Safety Code §§386.201-386.205 and pursuant to §25.182 of this title, and independent system operators (ISO) and regional transmission organizations (RTO).

(c) **Definitions**. The words and terms in §25.182(c) of this title shall apply to this section, unless the context clearly indicates otherwise.

(d) **Reporting.** Each electric utility and grantee shall file by April 1, of each program year an annual energy efficiency report. The annual energy efficiency report shall include the information required under §25.181(h)(4) of this title and paragraphs (1) - (5) of this subsection in a format prescribed by the commission.

(1) Load data within the applicable service area. If such information is available from an ISO or RTO in the power region in which the electric utility or grantee operates, then the ISO or RTO shall provide this information to the commission instead of the electric utility or grantee.

(2) The reduction in peak demand attributable to energy efficiency programs implemented under §25.181 and §25.182 of this title, in kW by county, by type of program and by funding source.

(3) The reduction in energy consumption attributable to energy efficiency programs implemented under §25.181 and §25.182 of this title, in kWh by county, by type of program and by funding source.

(4) Any data to be provided under this section that is proprietary in nature shall be filed in accordance with §22.71(d) of this title (relating to Filing of Pleadings, Documents and Other Materials.

(5) Any other information determined by the commission to be necessary to quantify the air contaminant emission reductions.

(e) **Evaluation.**

(1) Annually the commission, in cooperation with the Laboratory, shall provide the Texas Commission on Environmental Quality (TCEQ) a report, by county, that compiles the data provided by the utilities and grantees affected by this section and quantifies the reductions of energy consumption, peak demand and associated air contaminant emissions.

(A) The Laboratory shall ensure that all data that is proprietary in nature is protected from disclosure.

(B) The commission and the Laboratory shall ensure that the report does not provide information that would allow market participants to gain a competitive advantage.

(2) Every two years, the commission, in cooperation with the Energy Efficiency Implementation Project shall evaluate the Energy Efficiency Grant Program under §25.182 of this title.

(f) **Effective date:** This section shall be in effect for any energy efficiency programs pursuant to this section with a start date of January 1, 2003 and thereafter.

§25.191. Transmission Service Requirements.

(a) **Purpose.** The purpose of Subchapter I, Division 1 of this chapter (relating to Transmission and Distribution), is to clearly state the terms and conditions that govern transmission access in order to:

(1) facilitate competition in the sale of electric energy in Texas;

(2) preserve the reliability of electric service; and

(3) enhance economic efficiency in the production and consumption of electricity.

(b) **Applicability.** Unless otherwise explicitly provided, Division 1 of this subchapter (relating to Open-Access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas) applies to transmission service providers (TSPs), as defined in §25.5 of this title (relating to Definitions), which include river authorities and other electric utilities, municipally-owned utilities, and electric cooperatives. The transmission service standards described in Division 1 of this subchapter also apply to transmission service to, from, and over the direct-current interconnections between the Electric Reliability Council of Texas (ERCOT) region and areas outside of the ERCOT region (DC ties), to the extent that tariffs for such service incorporating the terms of Division 1 of this subchapter are approved for the transmission providers that own an interest in the interconnections. Some provisions of Division 1 explicitly apply to distribution service providers (DSPs), as defined in §25.5 of this title.

(c) **Nature of transmission service.** Transmission service allows for power delivery from generation resources to serve loads, inside and outside of the ERCOT region. Service provided pursuant to Division 1 of this subchapter permits municipally-owned utilities, electric cooperatives, power marketers, power generation companies, qualifying scheduling entities, retail electric providers (REPs), qualifying facilities, and distribution service providers (DSPs) to use the transmission systems of the TSPs in ERCOT. Transmission service shall be provided pursuant to Division 1 of this subchapter, commission-approved tariffs, the ERCOT protocols and, for TSPs subject to Federal Energy Regulatory Commission (FERC) jurisdiction, FERC requirements. Transmission service under Division 1 of this subchapter includes the provision of transmission service to an entity that is scheduling the export or import of power from the ERCOT region across a DC tie. The rules in Division 1 of this subchapter do not require a municipally owned utility or electric cooperative that has not opted for customer choice to provide transmission service to a retail electric provider or retail customer in connection with the retail sale of electricity in its exclusive service area.

(d) **Obligation to provide transmission service.** Each TSP in ERCOT shall provide transmission service in accordance with the provisions of Division 1 of this subchapter.

(1) Where a TSP has contracted for another person to operate its transmission facilities, the person assigned to operate the facilities shall carry out the operating responsibilities of the TSP under Division 1 of this subchapter.

(2) The obligation to provide comparable transmission service applies to a TSP, even if the TSP's interconnection with the transmission service customer is through distribution, rather than transmission facilities. An electric cooperative that has not opted for customer choice or a municipally owned utility that has not opted for customer choice shall provide wholesale transmission service at distribution voltage when necessary to serve a wholesale customer.

(A) A TSP or a DSP that owns facilities for the delivery of electricity to a transmission service customer purchasing electricity at wholesale using facilities rated at less than 60 kilovolts shall provide the customer access to its facilities on a non-discriminatory basis.

(B) A TSP or DSP shall provide access to its facilities at the distribution level to a transmission service customer, in order to transmit power to a retail customer in an area in which the transmission service customer has the right to provide retail electric service. Such service shall be provided on a non-discriminatory basis and in accordance with PURA §39.203(h).

(C) A DSP shall file a tariff with the commission for wholesale transmission service at distribution level voltage if:

(i) The DSP is currently providing wholesale transmission service at distribution voltage; or

(ii) The DSP receives a valid request to provide wholesale transmission service at distribution voltage. The DSP shall file the tariff within 30 days of receiving the request.

(3) A TSP shall interconnect its facilities with new generating sources and construct facilities needed for such an interconnection, in accordance with Division 1 of this subchapter. A TSP shall use all reasonable efforts to communicate promptly with a power generation company to resolve any questions regarding the requests for service in a non-discriminatory manner. If a TSP or a power generation company is required to complete activities or to negotiate agreements as a condition of service, each party shall use due diligence to complete these actions within a reasonable time.

§25.192. Transmission Service Rates.

(a) **Tariffs.** Each transmission service provider (TSP) shall file a tariff for transmission service to establish its rates and other terms and conditions and shall apply its tariffs and rates on a non-discriminatory basis. The tariff shall apply to all distribution service providers (DSPs) and any entity scheduling the export of power from the Electric Reliability Council of Texas (ERCOT) region. The tariff shall not apply to any entity engaging in wholesale storage as described by §25.501(m) of this title (relating to Wholesale Market Design for the Electric Reliability Council of Texas) (storage entity).

(b) **Charges for transmission service delivered within ERCOT**. DSPs, excluding storage entities, shall incur transmission service charges pursuant to the tariffs of the TSP.

(1) A TSP's transmission rate shall be calculated as its commission-approved transmission cost of service divided by the average of ERCOT coincident peak demand for the months of June, July, August and September (4CP), excluding the portion of coincident peak demand attributable to wholesale storage load. A TSP's transmission rate shall remain in effect until the commission approves a new rate. The TSP's annual rate shall be converted to a monthly rate. The monthly transmission service charge to be paid by each DSP is the product of each TSP's monthly rate as specified in its tariff and the DSP's previous year's average of the 4CP demand that is coincident with the ERCOT 4CP.

(2) Payments for transmission services shall be consistent with commission orders, approved tariffs, and §25.202 of this title (relating to Commercial Terms for Transmission Service).

(c) **Transmission cost of service.** The transmission cost of service for each TSP shall be based on the expenses in Federal Energy Regulatory Commission (FERC) expense accounts 560-573 (or accounts with similar contents or amounts functionalized to the transmission function) plus the depreciation, federal income tax, and other associated taxes, and the commission-allowed rate of return based on FERC plant accounts 350-359 (or accounts with similar contents or amounts functionalized to the transmission function), less accumulated depreciation and accumulated deferred federal income taxes, as applicable.

(1) The following facilities are deemed to be transmission facilities:

(A) power lines, substations, reactive devices, and associated facilities, operated at 60 kilovolts or above, including radial lines operated at or above 60 kilovolts, except the step-up transformers and a protective device associated with the interconnection from a generating station to the transmission network;

(B) substation facilities on the high side of the transformer, in a substation where power is transformed from a voltage higher than 60 kilovolts to a voltage lower than 60 kilovolts;

(C) the portion of the direct-current interconnections with areas outside of the ERCOT region (DC ties) that are owned by a TSP in the ERCOT region, including those portions of the DC tie that operate at a voltage lower than 60 kilovolts; and

(D) capacitors and other reactive devices that are operated at a voltage below 60 kilovolts, if they are located in a distribution substation, the load at the substation has a power factor in excess of 0.95 as measured or calculated at the distribution voltage level without the reactive devices, and the reactive devices are controlled by an operator or automatically switched in response to transmission voltage.

(E) As used in subparagraphs (A) - (D) of this paragraph, reactive devices do not include generating facilities.

(2) For municipally owned utilities, river authorities, and electric cooperatives, the commission may permit the use of the cash flow method or other reasonable alternative methods of determining the

annual transmission revenue requirement, including the return element of the revenue requirement, consistent with the rate actions of the rate-setting authority for a municipally owned utility.

(3) For municipally owned utilities, river authorities, and electric cooperatives, the return may be determined based on the TSP's actual debt service and a reasonable coverage ratio. In determining a reasonable coverage ratio, the commission will consider the coverage ratios required in the TSP's bond indentures or ordinances and the most recent rate action of the rate-setting authority for the TSP.

(4) A municipally owned utility that is required to apply for a certificate of public convenience and necessity to construct, install, or extend a transmission facility within ERCOT pursuant to §25.101 of this title (relating to Certification Criteria) is entitled to recover, through the utility's wholesale transmission rate, reasonable payments made to a taxing entity in lieu of ad valorem taxes on that transmission facility, provided that:

(A) The utility enters into a written agreement with the governing body of the taxing entity related to the payments;

(B) The amount paid is the same as the amount the utility would have to pay to the taxing entity on that transmission facility if the facility were subject to ad valorem taxation;

(C) The governing body of the taxing entity is not the governing body of the utility; and

(D) The utility provides the commission with a copy of the written agreement and any other information that the commission considers necessary in relation to the agreement.

(5) The commission may adopt rate-filing requirements that provide additional details concerning the costs that may be included in the transmission costs and how such costs should be reported in a proceeding to establish transmission rates.

(d) **Billing units**. No later than December 1 of each year, ERCOT shall determine and file with the commission the current year's average 4CP demand for each DSP, or the DSP's agent for transmission service billing purposes, as appropriate, excluding the portion of coincident peak demand attributable to wholesale storage load. This demand shall be used to bill transmission service for the next year. The ERCOT average 4CP demand shall be the sum of the coincident peak of all of the ERCOT DSPs, excluding the portion of coincident peak demand attributable to wholesale storage load, for the four intervals coincident with ERCOT system peak for the months of June, July, August, and September, divided by four. As used in this section, a DSP's average 4CP demand is determined from the total demand, coincident with the ERCOT 4CP, of all customers connected to a DSP, including load served at transmission voltage, but excluding the load of wholesale storage entities. The measurement of the coincident peak shall be in accordance with commission-approved ERCOT protocols.

(e) **Transmission rates for exports from ERCOT.** Transmission service charges for exports of power from ERCOT will be assessed to transmission service customers for transmission service within the boundaries of the ERCOT region, in accordance with this section and the ERCOT protocols.

(1) A transmission service customer shall be assessed a transmission service charge for the use of the ERCOT transmission system in exporting power from ERCOT based on the megawatts that are actually exported, the duration of the transaction and the rates established under subsections (c) and (d) of this section. Billing intervals shall consist of a year, month, week, day, or hour.

(2) The monthly on-peak transmission rate will be one-fourth the TSP's annual rate, and the monthly off-peak transmission rate will be one-twelfth its annual rate. The peak period used to determine the applicable transmission rate for such transactions shall be the months of June, July, August, and September.

(3) The DSP or an entity scheduling the export of power over a DC tie is solely responsible to the TSP for payment of transmission service charges under this subsection.

(4) A transmission service customer's charges for use of the ERCOT transmission system for export purposes on a monthly basis shall not exceed the annual transmission charge for the transaction.

(f) **Transmission revenue.** Revenue from the transmission of electric energy out of the ERCOT region over the DC ties that is recovered under subsection (e) of this section shall be credited to all transmission service customers as a reduction in the transmission cost of service for TSPs that receive the revenue.

(g) **Revision of transmission rates.** Each TSP in the ERCOT region shall periodically revise its transmission service rates to reflect changes in the cost of providing such services. Any request for a change in transmission rates shall comply with the filing requirements established by the commission under this section.

(h) **Interim Update of Transmission rates.**

(1) **Frequency.** Each TSP in the ERCOT region may apply to update its transmission rates on an interim basis not more than once per calendar year to reflect changes in its invested capital. Upon the effective date of an amendment to §25.193 pursuant to an order in Project Number 37909, *Rulemaking Proceeding to Amend P.U.C. Subst. R. 25.193, Relating to Distribution Service Provider Transmission Cost Recovery factors (TCRF)*, that allows a distribution service provider to recover, through its transmission cost recovery factor, all transmission costs charged to the distribution service provider by TSPs, each TSP in the ERCOT region may apply to update its transmission rates on an interim basis not more than twice per calendar year to reflect changes in its invested capital. If the TSP elects to update its transmission rates, the new rates shall reflect the addition and retirement of transmission facilities and include appropriate depreciation, federal income tax and other associated taxes, and the commission-authorized rate of return on such facilities as well as changes in loads. If the TSP does not have a commission-authorized rate of return, an appropriate rate of return shall be used.

(2) **Reconciliation.** An update of transmission rates under paragraph (1) of this subsection shall be subject to reconciliation at the next complete review of the TSP's transmission cost of service, at which time the commission shall review the costs of the interim transmission plant additions to determine if they were reasonable and necessary. Any amounts resulting from an update that are found to have been unreasonable or unnecessary, plus the corresponding return and taxes, shall be refunded with carrying costs determined as follows: for the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the TSP's rates set in that complete review of the TSP's transmission cost of service, carrying costs shall be calculated using the same rate of return that was applied to the transmission investments included in the update. For the time period beginning with the effective date of the TSP's rates set in that complete review of the TSP's transmission cost of service, carrying costs shall be calculated using the TSP's rate of return authorized in that complete review.

(3) **Future consideration of effect on TSP's financial risk and rate of return.** For a TSP that has increased its rates pursuant to paragraph (1) of this subsection, the commission may, in setting rates in the next complete review of the TSP's transmission cost of service, expressly consider the effects of reduced regulatory lag resulting from the interim updates to the TSP's rates and the concomitant impact on the TSP's financial risk and rate of return.

(4) **Commission processing of application**. The commission shall process an application filed pursuant to paragraph (1) of this subsection in the following manner.

(A) **Notice and intervention deadline.** The applicant shall provide notice of its application to all parties in the applicant's last complete review of the applicant's transmission cost of service and all of the distribution service providers listed in the last docket in which the commission set the annual transmission service charges for the Electric Reliability Council of Texas. The intervention deadline shall be 21 days from the date service of notice is completed.

(B) **Sufficiency of application.** A motion to find an application materially deficient shall be filed no later than 21 days after an application is filed. The motion shall be served on the applicant by hand delivery, facsimile transmission, or overnight courier delivery, or by e-mail if agreed to by the applicant or ordered by the presiding officer. The motion shall specify the nature of the deficiency and the relevant portions of the application, and cite the particular requirement with which the application is alleged not to comply. The applicant's response to a motion to find an application materially deficient shall be filed no later than five working days after such motion is received. If within ten working days after the deadline for filing a motion to find an application materially deficient, the presiding officer has not filed a written order concluding that material deficiencies exist in the application, the application is deemed sufficient.

(C) **Review of application.** A proceeding initiated pursuant to paragraph (1) of this subsection is eligible for disposition pursuant to §22.35(b)(1) of this title (relating to Informal Disposition). If the requirements of §22.35 of this title are met, the presiding officer shall issue a notice of approval within 60 days of the date a materially sufficient application is filed unless good cause exists to extend this deadline or the presiding officer determines that the proceeding should be considered by the commission.

(5) **Filing Schedule.** The commission may prescribe a schedule for providers of transmission services to file proceedings to revise the rates for such services.

(6) **DSP's right to pass through changes in wholesale rates.** A DSP may expeditiously pass through to its customers changes in wholesale transmission rates approved by the commission, pursuant to §25.193 of this title (relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)).

(7) **Reporting requirements.** TSPs shall file reports that will permit the commission to monitor their transmission costs and revenues, in accordance with any filing requirements and schedules prescribed by the commission.

§25.193. Distribution Service Provider Transmission Cost Recovery Factor (TCRF).

(a) **Application**. The provisions of this section apply to all investor-owned distribution service providers (DSPs) providing distribution service within the Electric Reliability Council of Texas (ERCOT) region to retail electric providers and other customers of the distribution system.

(b) **TCRF authorized.**

(1) A DSP subject to this section that is billed for transmission service by a transmission service provider (TSP) pursuant to §25.192 of this title (relating to Transmission Service Rates) shall be allowed to include within its tariff a TCRF clause that authorizes the DSP to charge or credit its customers for the amount of wholesale transmission cost changes approved or allowed by the commission to the extent that such costs vary from the transmission service cost utilized to fix the base rates of the DSP. The DSP shall update its TCRF twice per year on March 1 and September 1 to pass through the wholesale transmission cost changes billed by a TSP. For the March 1 update, the DSP shall file a request to update its TCRF no later than December 1; and for the September 1 update, no later than June 1. Within 45 days after a DSP files a request to update its TCRF, the commission shall issue an order establishing the amount of the revised TCRF and suspend the effective date of the revised TCRF as necessary so that the new TCRF charges will take effect on March 1 or September 1, as applicable.

(2) A DSP shall include in its TCRF update calculation:

(A) the cost of wholesale transmission cost changes approved or allowed by the commission to the extent that such costs vary from the transmission service cost utilized to fix the rates of the DSP; and

(B) an adjustment amount, which shall equal:

(i) the actual costs paid by the DSP during the review period to TSPs as a result of increases in the TSPs' wholesale transmission rates above the wholesale transmission rates of the TSPs used to develop the retail transmission charges of the DSP in the DSP's last rate case; minus

(ii) the revenues recovered through the DSP's TCRF minus the portion of the adjustments approved by the commission in the DSP's most recent two TCRF filings that were in effect during the review period.

(iii) For a March 1 TCRF update, the adjustment shall reflect the six-month period beginning with the preceding May 1 and continuing through October 31 (review period); for a September 1 update, the adjustment shall reflect the six-month period beginning with the preceding November 1 and continuing through April 30 (review period). In no event shall a DSP's TCRF clause result in the DSP recovering more than its actual cost of wholesale transmission service included in the TCRF.

(c) **TCRF Formula.** The TCRF for each class shall be computed pursuant to the following formula:

$$\frac{\{[\sum_{i=1}^{N}(NWTR_i * NL_i) - \sum_{i=1}^{N}(BWTR_i * NL_i)] * 1/2 * ALLOC\} + ADJ}{BD}$$

Where:	$NWTR_i$ is the new wholesale transmission rate of a TSP, approved by the commission by order or pursuant to commission rules, since the DSP's last rate case;
	$BWTR_i$ is the base wholesale transmission rate of the TSP represented in the $NWTR_i$, used to develop the retail transmission charges of the DSP in the DSP's last rate case;
	NL_i is the DSP's individual 4CP load component of the total ERCOT 4CP load information used to develop the $NWTR_i$;
Where:	ADJ = $\sum_{p=1}^{6}\{EXP_p - (REV_p - ADJP1_p - ADJP2_p)\}$ ADJ = adjustment to Rate Class TCRF; EXP_p = transmission expenses not included in base rates for period p; REV_p = TCRF revenue for period p; $ADJP1_p$ = 1/6th of ADJ calculated in the previous TCRF update for the periods 5 and 6; $ADJP2_p$ = 1/6th of ADJ calculated in second previous TCRF update for the periods 1 through 4;
	ALLOC is the class allocator approved by the commission to allocate the transmission revenue requirement among classes in the DSP's last rate case, unless otherwise ordered by the commission; and,
	BD is each class's billing determinant (kilowatt-hour (kWh), or kilowatt (kW), or kilovolt-ampere (kVa)) for the previous March 1 through August 31 period for the March 1 TCRF update, and for the previous September 1 through February 28 period for the September 1 TCRF update.

(d) **TCRF charges.** A DSP's TCRF charge shall remain in effect until adjusted under this section or until the DSP's delivery rates change pursuant to a commission order in a rate proceeding.

(e) **Reports**. The DSP shall maintain and provide to the commission semi-annual reports containing all information required to monitor the costs recovered through the TCRF clause. This information includes, but is not limited to, the total estimated TCRF cost for each month, the actual TCRF cost on a cumulative basis, the amount of transmission costs included in base rates, total revenues resulting from the TCRF, and the calculation of the amount to be recovered under subsection (b)(2) of this section. The reports shall be filed by March 31 and September 30 of each year.

CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS

Subchapter I. TRANSMISSION AND DISTRIBUTION

DIVISION 1: OPEN-ACCESS COMPARABLE TRANSMISSION SERVICE FOR ELECTRIC UTILITIES IN THE ELECTRIC RELIABILITY COUNCIL OF TEXAS

DIVISION 1: OPEN-ACCESS COMPARABLE TRANSMISSION SERVICE FOR ELECTRIC UTILITIES IN THE ELECTRIC RELIABILITY COUNCIL OF TEXAS

§25.195. Terms and Conditions for Transmission Service.

(a) **Transmission service requirements.** As a condition to obtaining transmission service, a transmission service customer that owns electrical facilities in the Electric Reliability Council of Texas (ERCOT) region shall execute interconnection agreements with the transmission service providers (TSP) to which it is physically connected. The commission-approved standard generation interconnection agreement (SGIA) for the interconnection of new generating facilities shall be used by power generation companies, exempt wholesale generators, and TSPs. A standard agreement may be modified by mutual agreement of the parties to address specific facts presented by a particular interconnection request as long as the modifications do not frustrate the goal of expeditious, non-discriminatory interconnection and are not otherwise inconsistent with the principles underlying the SGIA.

(b) **Transmission service provider responsibilities.** The TSP will plan, construct, operate and maintain its transmission system in accordance with good utility practice in order to provide transmission service customers with transmission service over its transmission system in accordance with Division 1 of this subchapter (relating to Open-Access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas). The TSP shall, consistent with good utility practice, endeavor to construct and place into service sufficient transmission capacity to ensure adequacy and reliability of the network to deliver power to transmission service customer loads. The TSP will plan, construct, operate and maintain facilities that are needed to relieve transmission constraints, as recommended by ERCOT and approved by the commission, in accordance with Division 1 of this subchapter. The construction of facilities requiring commission issuance of a certificate of convenience and necessity is subject to such commission approval.

(c) **Construction of new facilities.** If additional transmission facilities or interconnections between TSPs are needed to provide transmission service pursuant to a request for such service, the TSPs where the constraint exists shall construct or acquire the facilities necessary to permit the transmission service to be provided in accordance with good utility practice, unless ERCOT identifies an alternative means of providing the transmission service that is less costly, operationally sound, and relieves the transmission constraint at least as effectively as would additional transmission facilities.

(1) When an eligible transmission service customer requests transmission service for a new generating source that is planned to be interconnected with a TSP's transmission network, the transmission service customer shall be responsible for the cost of installing step-up transformers to transform the output of the generator to a transmission voltage level and protective devices at the point of interconnection capable of electrically isolating the generating source owned by the transmission service customer. The TSP shall be responsible, pursuant to paragraph (2) of this subsection, for the cost of installing any other interconnection facilities that are designed to operate at a transmission voltage level and any other upgrades on its transmission system that may be necessary to accommodate the requested transmission service.

(A) An affected TSP may require the transmission service customer to pay a reasonable deposit or provide another means of security, to cover the costs of planning, licensing, and constructing any new transmission facilities that will be required in order to provide the requested service.

(B) If the new generating source is completed and the transmission service customer begins to take the requested transmission service, the TSP shall return the deposit or security to the transmission service customer. If the new generating source is not completed and new transmission facilities are not required, the TSP may retain as much of the deposit or security as is required to cover the costs it incurred in planning, licensing, and construction activities related to the planned new transmission facilities. Any repayment of a cash deposit shall include interest at a commercially reasonable rate based on that portion of the deposit being returned.

(2) A transmission service customer that is requesting transmission service, including transmission service at distribution voltage, may be required to make a contribution in aid of construction to cover all or part of the cost of acquiring or constructing additional facilities, if the acquisition of the additional facilities would impair the tax-exempt status of obligations issued by the provider of transmission services.

(d) **Curtailment of service.** In an emergency situation, as determined by ERCOT and at its direction, TSPs may interrupt transmission service on a non-discriminatory basis, if necessary, to preserve the stability of the transmission network and service to customers. Such curtailments shall be carried out in accordance with §25.200 of this title (relating to Load Shedding, Curtailments, and Redispatch) and in accordance with ERCOT protocols.

(e) **Filing of contracts.** Electric utilities shall file with the commission all new interconnection agreements within 30 days of their execution, including a cover letter explaining any deviations from the SGIA. These interconnection agreements shall be filed for the commission's information. Interconnection agreements are subject to commission review and approval upon request by any party to the agreement. Upon showing a good cause, appropriate portions of the filings required under this subsection may be subject to provisions of confidentiality to protect competitively sensitive commercial or financial information.

§25.196. Standards of Conduct.

(a) **Applicability.** This section applies to transmission service provider (TSP), as defined in §25.5 (relating to Definitions), that:

(1) is not required by the Public Utility Regulatory Act (PURA) §39.051 to unbundle generation and transmission activities; and

(2) has retail sales of total metered electric energy for the average of the three most recent calendar years that is greater than 6,000,000 megawatt hours.

(b) **Standards of conduct.** Each TSP subject to this section shall comply with the following standards:

(1) The employees of a TSP who are engaged in wholesale merchant functions (that is, the purchase or sale of electric energy at wholesale), other than purchases required under the Public Utility Regulatory Policies Act, shall not:

(A) conduct transmission system operations or reliability functions;

(B) have preferential access to the TSP's system control center and other facilities, beyond the access that is available to other market participants; or

(C) have preferential access to information about the TSP's transmission system that is not available to users of the electronic information network established in accordance with Division 1 of this subchapter.

(2) To the maximum extent practicable, employees of a TSP engaged in transmission system operations must function independently of employees engaged in wholesale merchant functions of the TSP. Employees engaged in transmission system operations may disclose information to employees of the TSP, or of an affiliate, who are engaged in wholesale merchant functions only through the electronic information network, if the information relates to the TSP's transmission system or offerings of ancillary services, including calculations of available transmission capacity and information concerning curtailments. Employees engaged in transmission system operations may not disclose to employees of the TSP, or of an affiliate, who are engaged in wholesale merchant functions, any information that is not publicly available concerning activities of any competitors of the TSP or any of its affiliates including requests for interconnection by a transmission service customer or requests by the Electric Reliability Council of Texas (ERCOT) for comments on the scope of a system security screening study.

(3) Information concerning transfers of persons between an organizational unit that is responsible for transmission system operations and a unit that is responsible for wholesale merchant functions shall be provided to the commission on a monthly basis and shall be made available, on request, to any market participant.

(4) If an employee of a TSP discloses or obtains information in a manner that is inconsistent with the requirements in this subsection, the TSP shall post a notice and details of the disclosure on the information network.

(5) Employees of a TSP engaged in transmission operations shall apply the rules in Division 1 of this subchapter and any tariffs relating to transmission service in a fair and impartial manner.

(6) Provisions of this section that allow no discretion shall be strictly applied, and where discretion is allowed, it shall be exercised in a non-discriminatory manner.

(7) This subsection shall not apply to data that do not relate to transmission service operations such as information on human resource policies.

§25.198. Initiating Transmission Service.

(a) **Initiating service.** Where a transmission service customer uses the transmission facilities in the Electric Reliability Council of Texas (ERCOT), whether its own facilities or those of another transmission service provider (TSP), to serve load or to make sales of energy to a third party, it shall apply for transmission service pursuant to this section, the ERCOT protocols, and commission-approved tariffs.

(b) **Conditions precedent for receiving service.** Subject to the terms and conditions of this section and in accordance with the ERCOT protocols and commission-approved tariffs, the TSP will provide transmission service to any transmission service customer as that term is defined in §25.5 of this title (relating to Definitions), provided that:

(1) the transmission service customer has complied with the applicable provisions of the ERCOT protocols;

(2) the transmission service customer and the TSP have completed the technical arrangements set forth in subsection (e) of this section; and

(3) if the transmission service customer operates electrical facilities that are interconnected to the facilities of a TSP, it has executed an interconnection agreement for service under this section or requested in writing that the TSP file a proposed unexecuted agreement with the commission.

(c) **Procedures for initiating transmission service.** A transmission service customer requesting transmission service under this section must comply with the ERCOT protocols and commission-approved tariffs.

(1) The transmission service customer shall provide all information deemed necessary by ERCOT to evaluate the transmission service.

(2) ERCOT must acknowledge the request within ten days of receipt. When the request is complete, the acknowledgment must include a date by which a response will be sent to the transmission service customer and a statement of any fees associated with responding to the request (e.g., system studies).

(3) If a transmission service customer fails to provide ERCOT with all information deemed necessary, then ERCOT shall notify the transmission service customer requesting service within 15 business days of receipt and specify the reasons for such failure. Wherever possible, ERCOT will attempt to remedy deficiencies in the application through informal communications with a transmission service customer.

(4) If ERCOT determines that a system security screening study is required, upon approval of the requesting transmission service customer, ERCOT will initiate such a study. If this study concludes that the transmission system is adequate to accommodate the request for service, either in whole or in part, or that no costs are likely to be incurred for new transmission facilities or upgrades, the transmission service will be initiated or tendered, within 15 business days of completion of the system security screening study.

(5) If ERCOT determines as a result of the system security screening study that additions or upgrades to the transmission system are needed to supply the transmission service customer's forecasted transmission requirements, the TSP will, upon the approval of the requesting transmission service customer, initiate a facilities study. When completed, a facilities study will include an estimate of the cost of any required facilities or upgrades and the time required to complete such construction and initiate the requested service.

(6) When a transmission service customer requests transmission service for a new resource under this section, ERCOT shall establish the scope of any system security screening study. The study will be used to determine the feasibility of integrating such new resource into the TSPs' transmission system,

and whether any upgrades of facilities providing transmission are needed. ERCOT will perform the system security screening study.

(A) ERCOT shall complete the system security screening study and provide the results to the transmission service customer within 90 days after the receipt of an executed study agreement and receipt from the transmission service customer of all the data necessary to complete the study. In the event ERCOT is unable to complete the study within the 90-day period, it will provide the transmission service customer a written explanation of when the study will be completed and the reasons for the delay.

(B) The requesting transmission service customer shall be responsible for the cost of the system security screening study and shall be provided with the results thereof, including relevant work papers to the extent such results and workpapers do not contain protected competitive information as reasonably determined by ERCOT.

(C) ERCOT will use a methodology consistent with good utility practice to conduct the system security screening study and shall coordinate with affected TSPs as needed in determining the most efficient means for all TSPs in the ERCOT region to assure feasibility of transmission service.

(d) **Facilities study.** Based on the results of the system security screening study, the TSP shall perform, pursuant to an executed facilities study agreement with the transmission service customer, a facilities study addressing the detailed engineering, design and cost of transmission facilities required to provide the requested transmission service.

(1) The facilities study will be completed as soon as reasonably practicable. If the TSP may charge a contribution in aid of construction under §25.195 of this title (relating to Terms and Conditions for Transmission Service), the TSP shall notify the transmission service customer whether it considers that a contribution in aid of construction is appropriate and the amount of the contribution. The TSP shall base its request on the information in the system security screening study, the facilities study, good utility practice, and §25.195 of this title.

(2) The transmission service customer shall be responsible for the reasonable cost of the facilities study pursuant to the terms of the facilities study agreement and shall be provided with the results of the facility study, including relevant workpapers.

(3) Pursuant to §25.195(c)(2) of this title, the TSP shall be responsible for the costs of any planning, designing, and constructing of facilities of the TSP associated with its addition of new facilities used to provide transmission service.

(e) **Technical arrangements to be completed prior to commencement of service.** Service under this section shall not commence until the installation has been completed of all equipment specified under the interconnection agreement, consistent with guidelines adopted by the national reliability organization and ERCOT, except that the TSP shall provide the requested transmission service, to the extent that such service does not impair the reliability of other transmission service. The TSP shall exercise reasonable efforts, in coordination with the transmission service customer, to complete such arrangements as soon as practical prior to the service commencement date.

(f) **Transmission service customer facilities.** The provision of transmission service shall be conditioned upon the transmission service customer's constructing, maintaining and operating the facilities on its side of each point of interconnection that are necessary to reliably interconnect and deliver power from a resource to the transmission system and from the transmission system to the transmission service customer's loads.

(g) **Transmission arrangements for resources located outside of the ERCOT region.** If a transmission service customer intends to import power from outside the ERCOT region, it shall make any transmission arrangements necessary for delivery of capacity and energy from the resource to an interconnection with ERCOT.

(h) **Changes in service requests.** A transmission service customer's decision to cancel or delay the addition of a new resource shall not relieve the transmission service customer of the obligation to pay for any study conducted in accordance with this section.

(i) **Annual load and resource information updates.** A transmission service customer shall provide ERCOT with annual updates of load and resource forecasts for the following five-year period. The transmission service customer also shall provide ERCOT with timely written notice of material changes in any other information provided in its application relating to the transmission service customer's load, resources, or other aspects of its facilities or operations affecting the TSP's ability to provide reliable service under Division 1 of this subchapter.

(j) **Termination of transmission service.** A transmission service customer may terminate transmission service after providing ERCOT and the appropriate TSP with written notice of its intention to terminate. A transmission service customer's provision of notice to terminate service under this section shall not relieve the transmission service customer of its obligation to pay TSPs any rates, charges, or fees, including contributions in aid of construction, for service previously provided under the applicable interconnection service agreement, and which are owed to TSPs as of the date of termination.

§25.199. Transmission Planning, Licensing and Cost-Recovery for Utilities within the Electric Reliability Council of Texas.

(a) **Purpose.** The purpose of this section is to prescribe the procedures and criteria under which the commission may require an electric utility or a transmission and distribution utility to construct or enlarge facilities to ensure safe, reliable service and to reduce transmission constraints within the Electric Reliability Council of Texas (ERCOT) in a cost-effective manner.

(b) **Applicability.** This section applies to all electric utilities, transmission and distribution utilities and ERCOT. This section does not apply to an electric utility or transmission and distribution utility located outside of the ERCOT region. For the purpose of this section, an electric utility includes a municipally-owned utility and an electric cooperative.

(c) **Eligibility for filing a request under this section**. Any interested party in the ERCOT electric market may file a request for an order under this section.

(d) **Filing requirements.** Sections 22.251(d) – (f) of this title (relating to Review of ERCOT Conduct) shall apply to proceedings under this section, except as otherwise provided. In accordance with §22.251(f) of this title, ERCOT shall file a response to the application within 14 days after it receives the notice required under subsection (g) of this section. ERCOT shall include as part of the response all existing, non-privileged documents that support ERCOT's position on the issues identified by the applicant.

(e) **Standard for review.** The commission may require an electric utility or a transmission and distribution utility to construct or enlarge transmission facilities to ensure safe and reliable service for the state's electric markets and to reduce transmission constraints within ERCOT in a cost-effective manner where the constraints are such that they are not being resolved through Chapter 37 or the ERCOT transmission planning process. An applicant bears the burden of persuading the commission that the facilities are necessary to ensure safe and reliable service for the state's electric markets or to reduce transmission constraints within ERCOT in a cost-effective manner.

(f) **Threshold requirements**. In its request, the applicant must plead facts that are sufficient, if proven, to show that the request is likely to be granted under the standards of this section.

(1) The applicant must provide sufficient information for the presiding officer to determine that the transmission constraints are not being resolved through Chapter 37 or the ERCOT transmission planning process. In particular, the applicant shall demonstrate that:

(A) the facilities are not the subject of a pending application for a certificate of convenience and necessity; and

(B) the facilities have been presented to and considered in the ERCOT transmission planning process and have been rejected, or have been approved with one or more conditions that are tantamount to rejection, either in the regional planning process or by the board of directors, or ERCOT has not acted upon the application within a reasonable amount of time.

(2) Within 20 days after ERCOT has filed its response to the complaint pursuant to subsection (d) of this section, the presiding officer shall make a recommendation as to whether the applicant has shown that the facts alleged, if proved, would warrant granting the application. The recommendation shall be submitted to the commission for its consideration and action at an open meeting.

(g) **Notice.** An applicant shall serve copies of its complaint and other documents, in accordance with §22.74 of this title (relating to Service of Pleadings and Documents), and in particular shall serve a copy of the complaint on ERCOT's General Counsel, every other entity from whom relief is sought, the Office of Public Utility Counsel, and any other party as may be appropriate. The notice required by ERCOT under §22.251(e) of this title shall also be provided to all transmission service providers in ERCOT.

(h) **Cost effectiveness.** Prior to granting a request filed pursuant to this section, the commission, together with the applicant or other parties as appropriate, may undertake a comprehensive cost-benefit analysis to consider both quantitative and qualitative costs and benefits of the proposed facilities. The analysis should consider at a minimum:

- (1) capital costs;
- (2) projected operation and maintenance costs;
- (3) carrying costs of the proposed upgrade;
- (4) a comparison of the cost of the proposed transmission project to other congestion-management techniques, such as system re-dispatch;
- (5) system reliability; and
- (6) impact on wholesale power costs in the ERCOT region.

(i) **Commission order**. If the commission concludes that the applicant has demonstrated that the facilities are needed to ensure safe and reliable service for the state's electric markets or to reduce transmission constraints within ERCOT in a cost-effective manner and that the constraints are not being resolved through Chapter 37 or the ERCOT transmission planning process, it shall order an electric or transmission and distribution utility or utilities to construct or enlarge the requested facilities.

- (1) The commission shall issue the final order in a proceeding initiated under this section not later than the 180th day after the filing of a complete, non-deficient request. Notwithstanding the foregoing, however, the 180-day deadline may be extended by the commission for good cause.
- (2) An order adopted under this section:
  - (A) except in the case of a municipally-owned utility, shall be contingent on the successful outcome of the subsequent certificate of convenience and necessity proceeding for the proposed facilities;
  - (B) except in the case of a municipally-owned utility, shall include a date, appropriate for the required construction, by which the electric utility or transmission and distribution utility ordered to construct the facilities will be required to file an application for a certificate of convenience and necessity, which may be extended by the commission for good cause;
  - (C) shall provide that the electric utility or transmission and distribution utility need not prove in any proceeding filed under PURA Chapter 37 that the construction or upgrade ordered is necessary for the convenience, accommodation, convenience or safety of the public, and need not address the factors listed in PURA §§37.056(c)(1)-(3) and (4)(E);
  - (D) except in the case of a municipally-owned utility, shall provide that in any proceeding filed under PURA Chapter 37 the electric utility or transmission and distribution utility shall present evidence regarding reasonable times for planning, licensing and constructing the line, so that an appropriate timeline may be included in any commission final order granting a certificate for a line; and,

(E) shall provide that the electric utility or transmission and distribution utility ordered to construct or enlarge the requested facilities may request the inclusion of construction work in progress (CWIP) in the electric utility or transmission and distribution utility's transmission cost of service rate proceeding. The commission will grant CWIP in accordance with §25.231 of this title (relating to Cost of Service).

§25.200. Load Shedding, Curtailments, and Redispatch.

(a) **Procedures.** The Electric Reliability Council of Texas (ERCOT) shall direct non-discriminatory emergency load shedding and curtailment procedures for responding to emergencies on the transmission system in accordance with ERCOT protocols.

(b) **Congestion management principles.** ERCOT shall develop and implement market mechanisms to manage transmission congestion in accordance with ERCOT protocols.

(c) **Transmission constraints.** During any period when ERCOT determines that a transmission constraint exists on the transmission system, and such constraint may impair the reliability of a transmission service provider's (TSP's) system or adversely affect the operations of either a TSP or a transmission service customer, ERCOT will take actions, consistent with good utility practice and the ERCOT protocols, that are reasonably necessary to maintain the reliability of the TSP's system and avoid interruption of service. ERCOT shall notify affected TSPs and transmission service customers of the actions being taken. In these circumstances, TSPs and transmission service customers shall take such action as ERCOT directs.

(1) Service to all transmission service customers shall be restored as quickly as reasonably possible.

(2) To the extent ERCOT determines that the reliability of the transmission system can be maintained by redispatching resources, or when redispatch arrangements are necessary to facilitate generation and transmission transactions for a transmission service customer, a transmission service customer will initiate procedures to redispatch resources, as directed by ERCOT.

(3) To the greatest extent possible, any redispatch shall be made on a least-cost non-discriminatory basis. Except in emergency situations, any redispatch under this section will provide for equal treatment among transmission service customers.

(4) ERCOT shall keep records of the circumstances requiring redispatch and the costs associated with each redispatch and file annual reports with the commission, describing costs, frequency and causes of redispatch. Costs for relieving capacity constraints shall be allocated in a manner consistent with the ERCOT protocols.

(d) **System reliability.** Notwithstanding any other provisions of this section, a TSP may, consistent with good utility practice and on a non-discriminatory basis, interrupt transmission service for the purpose of making necessary adjustments to, changes in, or repairs to its lines, substations and other facilities, or where the continuance of transmission service would endanger persons or property. In exercising this power, a TSP's liability shall be governed by §25.214 of this title (relating to Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities). In addition, notwithstanding any other provisions of this section, ERCOT may cause the interruption of transmission service for the purpose of maintaining ERCOT system stability and safety. In exercising this power, ERCOT shall not be liable for its ordinary negligence but may be liable for its gross negligence or intentional misconduct when legally due.

(1) In the event of any adverse condition or disturbance on the TSP's system or on any other system directly or indirectly interconnected with the TSP's system, the TSP, consistent with good utility practice, may interrupt transmission service on a non-discriminatory basis in order to limit the extent of damage from the adverse condition or disturbance, to prevent damage to generating or transmission facilities, or to expedite restoration of service. The TSP shall consult with ERCOT concerning any interruption in service, unless an emergency situation makes such consultation impracticable.

(2) The TSP will give ERCOT, affected transmission service customers, and affected suppliers of generation as much advance notice as is practicable in the event of an interruption.

(3) If a transmission service customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the transmission system, the transmission service customer shall be deemed to be in default. Any dispute over a transmission service customer's default shall be referred to alternative dispute resolution under §25.203 (relating to Alternative Dispute Resolution (ADR)) and may subject the transmission service customer to an assessment of an administrative penalty by the commission under Public Utility Regulatory Act §15.023.

(4) ERCOT shall report interruptions to the commission, together with a description of the events leading to each interruption, the services interrupted, the duration of the interruption, and the steps taken to restore service.

(e) **Transition provision on priority for transmission service and ancillary services.** Subsection (b) of this section is effective upon implementation of a single control area in the ERCOT region. Until that date, the current rules for priority of planned transmission service will continue, as provided by this subsection.

(1) Any redispatch under this section will provide for equal treatment among transmission service customers, subject to the priorities set out by this paragraph. Planned transmission service shall have priority over unplanned transmission service, and annual planned transmission service shall have priority over planned transmission service of a shorter duration.

(A) Subject to the foregoing priorities, for applications for planned or unplanned transmission service, complete applications filed earlier with the independent system operator shall have priority over applications that are filed later. Timely requests for annual planned transmission service will be accorded equal priority.

(B) Where a transmission service customer is using annual planned transmission service for a resource that becomes unavailable due to an unplanned outage or the expiration of a power supply contract, the transmission service customer shall have priority, in using the same transmission capacity to transmit power from a replacement resource, over other requests for unplanned transmission service or planned transmission service of a shorter duration.

(2) The price for redispatch services for annual planned transactions shall be based on the cost of providing the service, which shall be allocated among transmission service customers in proportion to each customer's share of the transmission cost of service, as determined by the commission under §25.192 of this title (relating to Transmission Service Rates). For redispatch required to accommodate an annual planned transaction, the electric utility providing the redispatch service shall provide information documenting the costs incurred to provide the service to the independent system operator. This information shall be available to affected persons.

(3) The cost of redispatch services for other transactions (including planned transmission service of a duration of less than a year) shall be borne by the transmission service customer for whose benefit the redispatch is made. Electric utilities shall provide binding advance bids for redispatch services for unplanned transactions. The participants in unplanned transactions shall be promptly notified by the independent system operator that their transactions may be or have been continued through redispatch; shall be informed of the cost of the redispatch measures; and shall have the opportunity to abandon or curtail their transactions to avoid additional redispatch costs.

(4) Electric utilities that have tariffs for ancillary services on the effective date of this section shall continue to provide services under those tariffs until ERCOT implements a single control area in the ERCOT region.

(5) The following words and terms, when used in this subsection, shall have the following meanings unless the context indicates otherwise:

(A) Planned resources — Generation resources owned, controlled, or purchased by a transmission customer, and designated as planned resources for the purpose of serving load.

(B) Planned transmission service — A service that permits a transmission service customer to use the transmission service providers' transmission systems for the delivery of power from planned resources to loads on the same basis as the transmission service providers use their transmission systems to reliably serve their native load customers.

(C) Unplanned transmission service — A service that permits a transmission service customer to use the transmission service providers' transmission systems to deliver energy to its loads from resources that have not been designated as the transmission service customer's planned resources.

§25.202. Commercial Terms for Transmission Service.

(a) **Billing and payment.** Within a reasonable time after the first day of each month, transmission service providers (TSPs) shall issue invoices for the prior month's transmission service to distribution service providers (DSPs) and customers responsible for the export of power from the Electric Reliability Council of Texas (ERCOT) region.

(1) An invoice for transmission service shall be paid so that the TSP will receive the funds by the 35th calendar day after the date of issuance of the invoice, unless the TSP and the transmission service customer agree on another mutually acceptable deadline. All payments shall be made in immediately available funds payable to the TSP, or by wire transfer to a bank named by the service provider or by other mutually acceptable terms.

(2) Interest on any unpaid amount shall be calculated by using the interest rate applicable to overbillings and underbillings, set by the commission, and compounded monthly. Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the TSP.

(3) In the event the transmission service customer fails, for any reason other than a billing dispute as described in subparagraph (A) of this paragraph, to make payment to the TSP on or before the due date, and such failure of payment is not corrected within 30 calendar days after the TSP notifies the customer to cure such failure, the customer shall be deemed to be in default.

(A) Upon the occurrence of a default, the TSP may initiate a proceeding with the commission to terminate service. If the commission finds that a default has occurred, the transmission service customer shall pay to the TSP an amount equal to two times the amount of the payment that the customer failed to pay, in addition to any other remedy ordered by the commission. In the event of a billing dispute between the TSP and the transmission service customer, the TSP will continue to provide service during the pendency of the proceeding, as long as the customer:

(i) continues to make all payments not in dispute; and

(ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute.

(B) If the transmission service customer fails to meet the requirements in subparagraph (A) of this paragraph, then the TSP will provide notice to the customer and to the commission of its intention to terminate service.

(C) Any dispute arising in connection with the termination or proposed termination of service shall be referred to the alternative dispute resolution process described in §25.203 of this title (relating to Alternative Dispute Resolution (ADR)).

(b) **Indemnification and liability.**

(1) Neither a transmission service customer nor TSP shall be liable to the other for damages for any act that is beyond such party's control, including any event that is a result of an act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, a curtailment, order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities, or by the making of necessary repairs upon the property or equipment of either party.

(2) Notwithstanding the provisions of paragraph (1) of this subsection, a transmission service customer and TSP shall assume all liability for, and shall indemnify each other for, any losses resulting from negligence or other fault in the design, construction, or operation of their respective facilities. Such liability shall include a transmission service customer or TSP's monetary losses, costs and expenses of defending an action or claim made by a third person, payments for damages related to the death or

injury of any person, damage to the property of the TSP or transmission service customer, and payments for damages to the property of a third person, and damages for the disruption of the business of a third person. This paragraph does not create a liability on the part of a TSP or transmission service customer to a retail customer or other third person, but requires indemnification where such liability exists. The indemnification required under this paragraph does not include responsibility for the TSP's or transmission service customer's costs and expenses of prosecuting or defending an action or claim against the other, or damages for the disruption of the business of the service provider or customer. The limitations on liability set forth in this subsection do not apply in cases of gross negligence or intentional wrongdoing.

(c) **Creditworthiness for transmission service.** For the purpose of determining the ability of a transmission service customer to meet its obligations related to transmission and any other obligation in Division 1 of this subchapter (relating to Open-Access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas), a TSP may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices.

(1) The TSP may require a transmission service customer to provide and maintain in effect during the term of service, an unconditional and irrevocable letter of credit in a reasonable amount as security to meet its responsibilities and obligations under Division 1 of this subchapter or an alternative form of security proposed by the customer and acceptable to the service provider and consistent with commercial practices established by the Uniform Commercial Code that reasonably protects the TSP against the risk of non-payment. Credit worthiness standards must be applied to all transmission service customers on a non-discriminatory basis.

(2) If a transmission service customer is creditworthy, no letter of credit or alternative form of security shall be required.

§25.203. Alternative Dispute Resolution (ADR).

(a) **Obligation to use alternative dispute resolution.** Subject to the right to seek direct commission review pursuant to subsection (f) of this section, in the event that a dispute arises under Division 1 of this subchapter (relating to Open-Access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas) and the dispute is not subject to the alternative dispute resolution procedures established in the commission-approved Electric Reliability Council of Texas (ERCOT) protocols, the parties to the dispute shall engage in mediation or other alternative means for resolving the dispute, prior to filing a complaint with the commission.

(b) **Referral to senior representatives.** Such disputes shall be referred for resolution to a designated senior representative of each of the parties to the dispute. The senior dispute representative shall be an individual who has authority to resolve the dispute. The senior dispute representatives shall make a good faith effort to resolve the dispute on an informal basis as promptly as practicable.

(c) **Mediation or arbitration.** In the event the parties are unable to resolve the dispute under subsection (b) of this section, the parties shall either:

(1) refer the matter to arbitration in accordance with procedures in subsection (d) of this section; or

(2) upon agreement of all parties, engage in mediation with the assistance of a neutral third party, mutually selected by all parties concerned, who has training or experience in mediation.

(d) **Arbitration.** If the parties choose to refer the matter to arbitration, pursuant to subsection (c) of this section:

(1) The commission shall maintain a commission-approved list of qualified persons available to serve on arbitration panels who are knowledgeable in electric utility matters, including electricity transmission and bulk power issues. The commission shall also maintain a separate list of qualified persons experienced in arbitration that may be available to chair the arbitration panels.

(2) A party shall initiate arbitration by filing a letter with the commission requesting that arbitration be scheduled. A copy of the letter shall be served upon the other party to the dispute at the same time the letter is filed with the commission.

(3) Only parties to the dispute may participate in the arbitration.

(4) **Arbitration panel.** Any arbitration initiated under this section shall be conducted before a three-member arbitration panel. Each party shall choose one arbitrator from the commission-approved list of panel members. In the event there are more than two parties to the dispute, the parties shall jointly select the two arbitrators. The two arbitrators chosen by the parties shall choose the chairman of the arbitration panel. If the two arbitrators chosen by the parties are unable to agree on the selection of a chairman, they will be dismissed and the parties shall select two different arbitrators from the approved list. The arbitrators are not required to choose the chairman from the names of persons on the commission's list of panel members so long as the person chosen is qualified as an arbitrator. Panel members chosen shall not have any current or past substantial business or financial relationships with any party to the arbitration (other than previous arbitration experience). The chairman of the panel shall make all necessary arrangements for arbitration to commence within ten working days of completion of the panel.

(5) **Procedures.** The arbitrators shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable commission rules. The panel may request that the parties provide additional technical information

relevant to the dispute. The arbitration panel shall render a decision within 30 calendar days from the closing of the evidentiary record of the arbitration and shall notify the parties in writing of such decision and the reasons therefore. The decision shall not be considered precedent in any future proceeding.

(6) **Basis for decision.** The arbitrators shall be authorized only to interpret and apply the provisions of the commission's rules relating to transmission services, the commission-approved ERCOT protocols, the transmission service provider's (TSP) transmission tariff, and any service agreement entered into under that tariff. The arbitrators shall have no power to modify or change any of the above in any manner. The arbitrators may agree with the positions of one or more of the parties, or may recommend a compromise position.

(7) If any party to the arbitration files a complaint before the commission, the arbitration panel decision shall be filed in the commission's Central Records and shall be considered by the commission in preparing a Preliminary Order in the complaint proceeding. The complaint shall be docketed and may be referred to the State Office of Administrative Hearings. The decision may be admitted in evidence in any such complaint proceeding.

(8) **Costs.** Each party shall be responsible for the following costs, if applicable:

(A) its own costs incurred during the arbitration process;

(B) its pro rata share of the costs of the three arbitrators, pooled and shared evenly among the parties.

(e) **Effect of pending alternative dispute resolution.** The transaction which is the subject of the dispute shall be allowed to go forward pending the resolution of the dispute to the extent system reliability is not affected.

(f) **Effect on rights under law.** Nothing in this section shall restrict the rights of any party to file a complaint with the commission under relevant provisions of the Public Utility Regulatory Act or with the Federal Energy Regulatory Commission under the Federal Power Act or the right of a TSP to seek changes in the rates or terms for transmission, following the completion of the alternative dispute resolution procedures in this section.

(1) Use or application of the arbitration provisions in this subsection does not affect the jurisdiction of the commission over any matters arising under this section.

(2) Nothing in this section shall restrict the right of a market participant to file a petition seeking direct relief from the commission without first utilizing the alternative dispute resolution process where an action by a TSP, distribution service provider (DSP), or ERCOT might inhibit the ability of a transmission service customer to provide continuous and adequate service to its customers.

(3) Because of the imminent threat to the health and welfare of a TSP's customers in the event of a reliability problem, a petitioner's dispute will be heard by the commission in an emergency session except in those instances where a quorum of the commission is not present. In those instances where a quorum is not present, the chairman of the commission shall have the authority to issue an interim order to resolve the dispute so as to protect the reliability of the system, with the order remaining in effect until such time as a quorum is present.

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

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

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

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

(1) **Application for interconnection and parallel operation or application** -- The form of application prescribed in subsection (q) of this section.

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

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

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

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

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

(7) **Interconnection agreement** -- The form of agreement prescribed in subsection (p) of this section. The interconnection agreement sets forth the contractual conditions under which a company and a customer agree that one or more facilities may be interconnected with the company's utility system.

(8) **Inverter-based protective function** -- A function of an inverter system, carried out using hardware and software, that is designed to prevent unsafe operating conditions from occurring before, during, and after the interconnection of an inverter-based static power converter unit with a utility system. For purposes of this definition, unsafe operating conditions are conditions that, if left uncorrected, would result in harm to personnel, damage to equipment, unacceptable system instability or operation outside legally established parameters affecting the quality of service to other customers connected to the utility system.

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

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

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

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

(13) **Pre-certified equipment** -- 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 tariff for interconnection and parallel operation of distributed generation prescribed in subsection (q) of this section.

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

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

(d) **Terms of Service.**

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

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

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

(4) **New or amended interconnection agreements.** A new or amended interconnection agreement entered into 30 or more days after the commission's approval of an electric utility's compliance tariff filed pursuant to paragraph (5) of this subsection shall meet the requirements of this section.

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

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

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

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

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

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

(5) **Lack of approved application and interconnection agreement.** In order to interconnect distributed generation to a utility system, a customer must first submit to the utility an application for interconnection and parallel operation with the utility system and execute an interconnection agreement on the forms prescribed by the commission. The utility may refuse to connect or may disconnect the customer's facility if such application has not been received and approved.

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

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

(1) **Distributed generation facilities for which no pre-interconnection study fees may be charged.** A utility may not charge a customer a fee to conduct a pre-interconnection study for pre-certified distributed generation units up to 500 kW that export not more than 15% of the total load on a single radial feeder and contribute not more than 25% of the maximum potential short circuit current on a single radial feeder.

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

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

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

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

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

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

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

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

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

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

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

(i) **Pre-Interconnection studies for network interconnection of distributed generation.** Prior to charging a pre-interconnection study fee for a network interconnection of distributed generation, a utility shall first advise the customer of the potential problems associated with interconnection of distributed generation with its network system. For potential interconnections to network systems there shall be no pre-interconnection study fee assessed for a facility with inverter systems under 20 kW. For all other facilities the utility may charge the customer a fee to offset its costs incurred in the conduct of the pre-interconnection study. In those instances where a utility conducts an interconnection study, the following shall apply:

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

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

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

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

(j) **Communications concerning proposed distributed generation projects.** In the course of processing applications for interconnection and parallel operation and in the conduct of pre-interconnection studies, customers shall provide the utility detailed information concerning proposed distributed generation facilities. Such communications concerning the nature of proposed distributed generation facilities shall be made subject to the terms of §25.84 of this title (relating to Annual Reporting of Affiliate Transactions for Electric Utilities), §25.272 of this title (relating to Code of Conduct for Electric Utilities and their Affiliates), and §25.273 of this title (relating to Contracts between Electric Utilities and their Competitive Affiliates). A utility and its affiliates shall not use such knowledge of proposed distributed generation projects submitted to it for interconnection or study to prepare competing proposals to the customer that offer either discounted rates in return for not installing the distributed generation, or offer competing distributed generation projects.

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

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

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

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

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

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

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

(3) Each electric utility shall provide convenient access through its internet web site to the names, telephone numbers, mailing addresses and electronic mail addresses for its distributed generation contact person.

(m) **Time periods for processing applications for interconnection and parallel operation.** In order to apply for interconnection the customer shall provide the utility a completed application for interconnection and parallel operation. The interconnection of distributed generation 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 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, except in situations in which a customer is not able to connect within two weeks following the completion of such upgrades, this time may be extended by agreement of the electric utility and the customer. The utility shall employ best reasonable efforts to complete such system upgrades in the shortest time reasonably practical.

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

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

(n) **Reporting requirements.** Each electric utility shall maintain records concerning applications received for interconnection and parallel operation of distributed generation. Such records will include the name of the applicant, the business address of the applicant, and the location of the proposed facility by county, the capacity rating of the facility in kilowatts, whether the facility is a renewable energy resource as defined in §25.173 of this title (relating to Goal for Renewable Energy), the date each application is received, documents generated in the course of processing each application, correspondence regarding each application, and the final disposition of each application. The owner of a distributed generation facility that is interconnected under this section shall report to the utility any change in ownership of the facility and the cessation of operations of a facility within 14 days of such change. By March 30 of each year, every electric utility shall file with the commission a distributed generation interconnection report for the preceding calendar year that identifies each distributed generation facility interconnected with the utility's distribution system. The report shall list the new distributed generation facilities interconnected with the system since the previous year' report, any change in ownership or the cessation of operations of any distributed generation that has been reported to the electric utility and not included in the previous report, the capacity of each facility and whether it is a renewable energy resource, and the feeder or other point on the company's utility system where the facility is connected. The annual report shall also identify all applications for interconnection received during the previous one-year period, and the disposition of such applications.

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

(1) **Transmission**.

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

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

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

(p) **Agreement for Interconnection and Parallel Operation of Distributed Generation.**
Figure: 16 TAC §25.211(p)

(q) **Tariff for Interconnection and Parallel Operation of Distributed Generation**.
Figure: 16 TAC §25.211(q)

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

(a) **Purpose.** The purpose of this section is to describe the requirements and procedures for safe and effective connection and operation of distributed generation.

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

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

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

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

(b) **General interconnection and protection requirements.**

(1) The customer's generation and interconnection installation must meet all applicable national, state, and local construction and safety codes.

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

(3) The customer's generator shall be equipped with the necessary protective hardware and software designed to prevent connection or parallel operation of the generating equipment with the utility system unless the utility system service voltage and frequency is of normal magnitude.

(4) Pre-certified equipment may be installed on a company's utility systems in accordance with an approved interconnection control and protection scheme without further review of their design by the utility. When the customer is exporting to the utility system using pre-certified equipment, the protective settings and operations shall be those specified by the utility.

(5) The customer will be responsible for protecting its generating equipment in such a manner that utility system outages, short circuits or other disturbances including zero sequence currents and ferroresonant over-voltages do not damage the customer's generating equipment. The customer's protective equipment shall also prevent unnecessary tripping of the utility system breakers that would affect the utility system's capability of providing reliable service to other customers.

(6) For facilities greater than two megawatts (MW), the utility may require that a communication channel be provided by the customer to provide communication between the utility and the customer's facility. The channel may be a leased telephone circuit, power line carrier, pilot wire circuit, microwave, or other mutually agreed upon medium.

(7) Circuit breakers or other interrupting devices at the point of common coupling must be capable of interrupting maximum available fault current. Facilities larger than two MW and exporting to the utility system shall have a redundant circuit breaker unless a listed device suitable for the rated application is used.

(8) The customer will furnish and install a manual disconnect device that has a visual break that is appropriate to the voltage level (a disconnect switch, a draw-out breaker, or fuse block), and is accessible to the utility personnel, and capable of being locked in the open position. The customer

shall follow the utility's switching, clearance, tagging, and locking procedures, which the utility shall provide for the customer.

(c) **Prevention of interference.** To eliminate undesirable interference caused by operation of the customer's generating equipment, the customer's generator shall meet the following criteria:

(1) **Voltage.** The customer will operate its generating equipment in such a manner that the voltage levels on the utility system are in the same range as if the generating equipment were not connected to the utility's system. The customer shall provide an automatic method of disconnecting the generating equipment from the utility system if a sustained voltage deviation in excess of +5.0 % or –10% from nominal voltage persists for more than 30 seconds, or a deviation in excess of +10% or –30% from nominal voltage persists for more than ten cycles. The customer may reconnect when the utility system voltage and frequency return to normal range and the system is stabilized.

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

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

(4) **Harmonics.** In accordance with IEEE 519 the total harmonic distortion (THD) voltage shall not exceed 5.0% of the fundamental 60 Hz frequency nor 3.0% of the fundamental frequency for any individual harmonic when measured at the point of common coupling with the utility system.

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

(d) **Control, protection and safety equipment requirements specific to single phase generators of 50 kilowatts (kW) or less connected to the utility's system**. Exporting to the utility system may require additional operational or protection devices and will require coordination of operations with the host utility. The necessary control, protection, and safety equipment specific to single-phase generators of 50 kW or less connected to secondary or primary systems include an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and a synchronizing check for synchronous and other types of generators with stand-alone capability.

(e) **Control, protection and safety equipment requirements specific to three-phase synchronous generators, induction generators, and inverter systems.** This subsection specifies the control, protection, and safety equipment requirements specific to three phase synchronous generators, induction generators, and inverter systems. Exporting to the utility system may require additional operational or protection devices and will require coordination of operations with the utility.

(1) **Three phase synchronous generators.** The customer's generator circuit breakers shall be three-phase devices with electronic or electromechanical control. The customer is solely responsible for

properly synchronizing its generator with the utility. The excitation system response ratio shall not be less than 0.5. The generator's excitation system(s) shall conform, as near as reasonably achievable, to the field voltage versus time criteria specified in American National Standards Institute Standard C50.13-1989 in order to permit adequate field forcing during transient conditions. For generating systems greater than two MW the customer shall maintain the automatic voltage regulator (AVR) of each generating unit in service and operable at all times. If the AVR is removed from service for maintenance or repair, the utility's dispatching office shall be notified.

(2) **Three-phase induction generators and inverter systems.** Induction generation may be connected and brought up to synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured on the utility system side at the point of common coupling is within the visible flicker stated in subsection (c)(2) of this section. Otherwise, the customer may be required to install hardware or employ other techniques to bring voltage fluctuations to acceptable levels. Line-commutated inverters do not require synchronizing equipment. Self-commutated inverters whether of the utility-interactive type or stand-alone type shall be used in parallel with the utility system only with synchronizing equipment. Direct-current generation shall not be operated in parallel with the utility system.

(3) **Protective function requirements.** The protective function requirements for three phase facilities of different size and technology are listed below.

(A) Facilities rated ten kilowatts (kW) or less must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and a manual or automatic synchronizing check (for facilities with stand alone capability).

(B) Facilities rated in excess of ten kW but not more than 500 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, a manual or automatic synchronizing check (for facilities with stand alone capability), either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, and reverse power sensing if the facility is not exporting (unless the generator is less than the minimum load of the customer).

(C) Facilities rated more than 500 kW but not more than 2,000 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, an automatic synchronizing check (for facilities with stand alone capability) and reverse power sensing if the facility is not exporting (unless the facility is less than the minimum load of the customer). If the facility is exporting power, the power direction protective function may be used to block or delay the under frequency trip with the agreement of the utility.

(D) Facilities rated more than 2,000 kW but not more than 10,000 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, an automatic synchronizing check and AVR for facilities with stand alone capability, and reverse power sensing if the facility is not exporting (unless the facility is less than the minimum load of the customer). If the facility is exporting power, the power direction protective function may be used to block or delay the under frequency trip with the agreement of the utility. A telemetry/transfer trip may also be required by the company as part of a transfer tripping or blocking protective scheme.

(f) **Facilities not identified.** In the event that standards for a specific unit or facility are not set out in this section, the company and customer may interconnect a facility using mutually agreed upon technical standards.

(g) **Requirements specific to a facility paralleling for sixty cycles or less (closed transition switching).** The protective devices required for facilities ten MW or less which parallel with the utility system for 60 cycles or less are an interconnect disconnect device, a generator disconnect device, an automatic synchronizing check for generators with stand alone capability, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and either a ground over-voltage trip or a ground over-current trip depending on the grounding system, if required by the utility.

(h) **Inspection and start-up testing.** The customer shall provide the utility with notice at least two weeks before the initial energizing and start-up testing of the customer's generating equipment and the utility may witness the testing of any equipment and protective systems associated with the interconnection. The customer shall revise and re-submit the application with information reflecting any proposed modification that may affect the safe and reliable operation of the utility system.

(i) **Site testing and commissioning.** Testing of protection systems shall include procedures to functionally test all protective elements of the system up to and including tripping of the generator and interconnection point. Testing will verify all protective set points and relay/breaker trip timing. The utility may witness the testing of installed switchgear, protection systems, and generator. The customer is responsible for routine maintenance of the generator and control and protective equipment. The customer will maintain records of such maintenance activities, which the utility may review at reasonable times. For generation systems greater than 500 kW, a log of generator operations shall be kept. At a minimum, the log shall include the date, generator time on, and generator time off, and megawatt and megavar output. The utility may review such logs at reasonable times.

(j) **Metering.** Consistent with Chapter 25, Subchapter F of this title (relating to Metering), the utility may supply, own, and maintain all necessary meters and associated equipment to record energy purchases by the customer and energy exports to the utility system. The customer shall supply at no cost to the utility a suitable location on its premises for the installation of the utility's meters and other equipment. If metering at the generator is required in such applications, metering that is part of the generator control package will be considered sufficient if it meets all the measurements criteria that would be required by a separate stand alone meter.

§25.213. Metering for Distributed Renewable Generation and Certain Qualifying Facilities.

(a) **Application.**
This section applies to transmission and distribution utilities, excluding river authorities; an electric utility subject to Public Utility Regulatory Act (PURA) Chapter 39, Subchapter L; distributed renewable generation owners as defined in §25.217 of this title (relating to Distributed Renewable Generation); and the entity responsible for settlement.

(b) **Metering.**

(1) Upon request by a customer that has, or is in the process of installing distributed renewable generation with a capacity of less than 50 kilowatts (kW) on the retail electric customer's side of the meter and that desires to measure the generation's out-flow production, an electric utility shall provide metering at the point of common coupling using one or two meters that separately measure both the customer's electricity consumption from the distribution network and the out-flow that is delivered from the customer's side of the meter to the distribution network and separately report each metered value to the transmission and distribution utility. The two metered values shall be separately accounted for by the entity responsible for settlement.

(2) Upon request by a retail electric customer that has, or is in the process of installing distributed renewable generation with a capacity equal to or greater than 50 kW up to 2,000 kW on the retail electric customer's side of the meter, an electric utility shall provide one or two interval data recorders at the point of common coupling that separately measure both the customer's electricity consumption from the distribution network and the out-flow that is delivered from the retail electric customer's side of the meter to the distribution network and separately report each metered value to the transmission and distribution utility. The two metered values shall be separately accounted for by the entity responsible for settlement.

(3) Upon request by a retail electric customer that has, or is in the process of installing distributed renewable generation with a capacity of less than 50 kW on the retail electric customer's side of the meter and that does not desire to measure the generation's out-flow production, an electric utility shall provide metering in accordance with paragraph (1) of this subsection or, at the electric utility's option, install a meter that measures the customer's electricity consumption from the distribution network but does not measure the out-flow that is delivered from the retail electric customer's side of the meter to the distribution network. Unless an existing distributed renewable generation owner requests to have the existing meter replaced, the electric utility may, at its option and expense, replace an existing distributed renewable generation owner's meter with a meter of a type specified in this rule.

(4) Pursuant to the applicable schedule in its tariff, an electric utility shall charge for the customer's electricity consumption from the distribution network as measured by the metering installed pursuant to paragraph (1), (2) or (3) of this subsection.

(5) An electric utility shall not provide metering for purposes of PURA §39.914(d) and PURA §39.916(f), that is inconsistent with paragraph (1), (2) or (3) of this subsection, unless ordered by the commission.

(6) The distributed renewable generation owner shall pay any significant differential cost of the metering.

(7) Electric utilities shall file tariffs for metering under this section within 60 days of its effective date.

(8) Distributed renewable generation owners may begin selling out-flow at any time. Electric utilities are required to comply with paragraphs (1), (2) and (3) of this subsection, as they relate to

reporting the two metered values. The entity responsible for settlement is required to accept the meter data provided pursuant to paragraph (1), (2) or (3) of this subsection.

(9) The entity responsible for settlement shall have a process for settlement of electricity consumption and out-flow that reflects time of generation.

(c) **Metering Provisions Specific to an Electric Utility Subject to PURA Chapter 39, Subchapter L.**

(1) This subsection applies to an electric utility subject to PURA Chapter 39, Subchapter L.

(2) An electric utility shall provide the additional option of interconnection through a single meter that runs forward and backward for a customer that is either:

(A) an apartment house occupied by low-income elderly tenants that qualifies for master metering under Texas Utilities Code §184.012(b) and the distributed renewable generation is reasonably expected to generate not less than 50 percent of the apartment house's annual electricity use; or

(B) has a qualifying facility with a design capacity of 50 kW or less and that uses a renewable energy resource.

(3) The net metering option provided by paragraph (2) of this subsection is available only if the distributed renewable generation or qualifying facility is rated to produce an amount of electricity that is less than or equal to:

(A) the customer's estimated annual kilowatt-hour consumption for a new apartment house or qualifying facility; or

(B) the amount of electricity the customer consumed in the year before installation of the distributed renewable generation or qualifying facility.

(4) Measured net consumption shall be billed under the electric utility's standard tariff schedule applicable to the customer. Measured net production shall be purchased in accordance with §25.217 of this title.

(5) The electric utility shall credit the payments to the customer's monthly electric service bill, and specify in the bill the amount of non-firm energy purchased in kilowatt hours. If the payment for non-firm energy supplied to the electric utility exceeds the total of the owner's monthly electric service bill, a credit balance of not more than $50 shall be carried forward to the owner's next monthly bill. The electric utility shall refund to the customer a credit balance that is not carried forward, or the portion of a credit balance that exceeds $50, if the credit balance is carried forward.

(6) An electric utility shall install, maintain, and retain ownership of the meter(s) and metering equipment installed for purposes of this subsection and may install load research metering equipment on the premises of the owner, at no expense to the owner.

(7) At the request of an electric utility, the customer shall:

(A) provide and install a meter socket, a metering cabinet, or both a socket and cabinet at a location designated by the electric utility on the premises of the owner; and

(B) provide, at no expense to the electric utility, a suitable location for the electric utility to install meters and equipment associated with billing and load research.

§25.214. Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities.

(a) **Purpose.** The purpose of this section is to implement Public Utility Regulatory Act (PURA) §39.203 as it relates to the establishment of non-discriminatory terms and conditions of retail delivery service, including delivery service to a Retail Customer at transmission voltage, provided by a transmission and distribution utility (TDU), and to standardize the terms of service among TDUs. A TDU shall provide retail delivery service in accordance with the terms and conditions set forth in this section to those Retail Customers participating in the pilot project pursuant to PURA §39.104 on and after June 1, 2001, and to all Retail Customers on and after January 1, 2002. By clearly stating these terms and conditions, this section seeks to facilitate competition in the sale of electricity to Retail Customers and to ensure reliability of the delivery systems, customer safeguards, and services.

(b) **Application.** This section, which includes the pro-forma tariff set forth in subsection (d) of this section, governs the terms and conditions of retail delivery service by all TDUs in Texas. The terms and conditions contained herein do not apply to the provision of transmission service by non-ERCOT utilities to retail customers.

(c) **Tariff.** Each TDU in Texas shall file with the commission a tariff to govern its retail delivery service using the pro-forma tariff in subsection (d) of this section. The provisions of this tariff are requirements that shall be complied with and offered to all REPs and Retail Customers unless otherwise specified. TDUs may add to or modify only Chapters 2 and 6 of the tariff, reflecting individual utility characteristics and rates, in accordance with commission rules and procedures to change a tariff; however the only modifications the TDU may make to 6.1.2.1 are to insert the commission-approved rates. Additionally, in Company specific discretionary service filings, Company shall propose timelines for discretionary services to the extent applicable and practical. Chapters 1, 3, 4, and 5 of the pro-forma tariff shall be used exactly as written. These chapters can be changed only through the rulemaking process. If any provision in Chapter 2 or 6 conflicts with another provision of Chapters 1, 3, 4, and 5, the provision found in Chapters 1, 3, 4, and 5 shall apply, unless otherwise specified in Chapters 1, 3, 4, and 5.

(d) **Pro-forma Retail Delivery Tariff.**
Tariff for Retail Delivery Service.
Figure: 16 TAC §25.214(d)(1)

§25.215. Terms and Conditions of Access by a Competitive Retailer to the Delivery System of a Municipally Owned Utility or Electric Cooperative that has Implemented Customer Choice.

(a) **Purpose.** The purpose of this section is to implement Public Utility Regulatory Act (PURA) §39.203 as it relates to the establishment of non-discriminatory terms and conditions of access by competitive retailers to the delivery systems of municipally owned utilities and electric cooperatives that have implemented customer choice. Retail delivery service, including delivery service to a retail customer at transmission voltage, shall be provided directly to retail customers by a municipally owned utility or an electric cooperative that has implemented customer choice. A municipally owned utility or an electric cooperative that has implemented customer choice shall provide retail delivery service in accordance with the rates, terms and conditions set forth in the delivery service tariffs promulgated by the municipally owned utility or an electric cooperative.

(b) **Application**. This section and the pro-forma access tariff set forth in subsection (d) of this section govern the terms and conditions of access by competitive retailers at the point of supply to retail customers connected to the delivery systems of municipally owned utilities and electric cooperatives that have implemented customer choice.

(c) **Access tariff.** Not later than the 90th day before the date customer choice is offered, each municipally owned utility or electric cooperative in Texas shall file with the Public Utility Commission of Texas (commission) its access tariff governing access by competitive retailers to retail customers connected to the delivery system of the municipally owned utility or electric cooperative using the pro-forma access tariff in subsection (d) of this section. A municipally owned utility or an electric cooperative may add to or modify only Chapters 2 and 5 of the access tariff, reflecting individual characteristics and rates. Chapters 1, 3, and 4 of the pro-forma access tariff shall be used exactly as written; these Chapters can be changed only through the rulemaking process. The access tariff, however, shall contain the name of the municipally owned utility or electric cooperative in lieu of "(Utility)".

(d) **Pro-forma access tariff**. The commission adopts by reference the form "Tariff for Competitive Retailer Access," effective date of August 23, 2001. This form is available in the commission's Central Records division and on the commission's website at www.puc.state.tx.us.

[See Chapter 25, Appendix V, for copy of "Tariff for Competitive Retailer Access" effective August 23, 2001.]

§25.216. Selection of Transmission Service Providers.

(a) **Application.** This section applies to any transmission service provider (TSP), or entity seeking to become a TSP, that submits an application to construct, operate, and maintain one or more competitive renewable energy zone (CREZ) Transmission Plan (CTP) Facilities.

(b) **Purpose.** The purpose of this section is to state the requirements that govern the selection and performance of one or more TSPs, or entities seeking to become TSPs, that will be responsible for the construction, operation, and maintenance of CTP Facilities.

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

(1) **CREZ Transmission Plan (CTP)** -- The transmission capacity plan required by §25.174(c)(2) of this title (relating to Competitive Renewable Energy Zones).

(2) **CTP Facility** -- A transmission line with or without a substation or any other transmission facility as identified in the CTP and designated by the commission.

(3) **CTP Proposal** -- An application to serve as a Designated TSP for one or more CTP Facilities that is submitted by an Interested TSP.

(4) **Designated TSP** -- An Interested TSP that the commission has designated to construct, operate, and maintain one or more CTP Facilities.

(5) **Interested TSP** -- An entity seeking status as a Designated TSP that meets the definition of a TSP as defined by §25.5(143) of this title (relating to Definitions) or that commits to meeting such definition as necessary to fulfill its obligations as a Designated TSP.

(6) **Funds from operations** -- Net income from continuing operations, depreciation and amortization, deferred income taxes, and other non-cash items.

(7) **Total debt** -- Long-term debt, current maturities, commercial paper, and other short-term borrowings.

(8) **Historically underutilized business --** Defined by Texas Government Code §481.191, as it may be amended.

(9) **Interest** -- Gross interest without subtracting capitalized interest and interest income.

(d) **Selection process.** The following steps outline the process the commission will employ to select Designated TSPs.

(1) The commission will initiate a proceeding that will invite each Interested TSP to file a CTP Proposal. The presiding officer shall set a procedural schedule that will enable the commission to decide the issues in the proceeding within 180 days after the deadline to file CTP Proposals unless good cause exists for setting a different schedule. The presiding officer may sever issues or CTP Proposals into separate proceedings.

(2) For each existing CTP Facility requiring an upgrade or modification, the commission will select the owner of the facility to be the Designated TSP for the CTP Facility, unless the owner requests that a different Interested TSP be selected or good cause exists to select another transmission service provider.

(3) For each new CTP Facility, the commission will select a Designated TSP pursuant to subsection (e) of this section.

(e) **Selection of Designated TSP.** The commission will evaluate each CTP Proposal received by considering, at a minimum, the current and expected capabilities of the Interested TSP to finance, license, construct, operate, and maintain the CTP Facility or Facilities in the most beneficial and cost-effective manner and the expertise of the Interested TSP's staff, the Interested TSP's projected capital costs and operating and maintenance costs for each CTP Facility, the Interested TSP's proposed schedule for development and completion of each CTP Facility, the Interested TSP's financial resources, the Interested TSP's expected use of historically underutilized businesses unless the Interested TSP is an electric cooperative or municipally owned utility, and the Interested TSP's understanding of the specific requirements to implement the CTP Facilities in its CTP Proposal and, if applicable, the Interested TSP's previous transmission experience and the Interested TSP's historical operating and maintenance costs for its existing transmission facilities.

(1) Each Interested TSP shall submit with its CTP Proposal the following information:

(A) A description of the process that the Interested TSP will use for the preparation of any required application for a certificate of convenience and necessity (CCN).

(B) For each CTP Facility transmission line, a general description of the proposed structure types (lattice, monopole, etc.) and composition (wood, steel, concrete, hybrid, etc.), conductor size and type, and right-of-way (ROW) width.

(C) The projected in-service date of each CTP Facility.

(D) A discussion of the type of resources, including relevant capability and experience (in-house labor, contractors, other TSPs, etc.) contemplated for use by the Interested TSP for the licensing, design, engineering, material and equipment procurement, ROW and land acquisition, construction, and project management related to the construction of each CTP Facility.

(E) A discussion of the type of resources contemplated by the Interested TSP for operating and maintaining each CTP Facility after it is placed in-service.

(F) A discussion of the capability and experience of the Interested TSP that would enable it to comply with all on-going scheduling, operating, and maintenance activities required for each CTP Facility, including those required by policies, rules, guidelines, and procedures established by the Electric Reliability Council of Texas independent system operator or other independent organization, if applicable.

(G) Resumes for key management personnel that will be involved in obtaining a transmission CCN and constructing, operating, and maintaining each CTP Facility.

(H) A discussion of the Interested TSP's business practices that demonstrates that its business practices are consistent with good utility practices for proper licensing, designing, ROW acquisition, constructing, operating, and maintaining CTP Facilities. The Interested TSP shall also provide the following information for the current calendar year and the five calendar years immediately preceding its filing under subsection (d)(1) of this section.

(i) A summary of law violations by the Interested TSP found by federal regulatory agencies, state public utility commissions, other regulatory agencies, or attorneys general.

(ii) A summary of any instances in which the Interested TSP is currently under investigation or is a defendant in a proceeding involving an attorney general or any state or federal regulatory agency, for violation of any laws, including regulatory requirements.

(I) For each CTP Facility transmission line, the estimated direct costs in current dollars to construct (including design, engineering, materials, labor, transportation and other necessary expenses but excluding ROW and land acquisition) representative tangent, 30-degree, and 90-degree structures suitable for the type of conductor that would be used.

The estimated costs shall be provided for each type of structure that might be used such as lattice, monopole, etc.

(J) For each CTP Facility transmission line, a detailed explanation and estimate of the Interested TSP's anticipated average annual operating and maintenance cost-per-mile in current dollars for the line for the first 10 years of operation. Also, the Interested TSP shall provide the actual average direct operating and maintenance cost-per-mile incurred by the Interested TSP for each of the last five calendar years for all transmission lines owned and operated by the Interested TSP that have the same voltage as the CTP Facility transmission line.

(K) The Interested TSP's overhead rate for managing third-parties, if the Interested TSP contemplates the use of third-parties to perform any function related to the licensing, construction, operation, or maintenance of the CTP Facility and the willingness of the Interested TSP to maintain the overhead rate for the managing of the third-party operation and maintenance for a fixed period of time after the CTP Facility has been energized.

(L) The Interested TSP's preexisting procedures and historical practices for acquiring ROW and land and managing ROW and land acquisition for transmission facilities. If the Interested TSP does not have such preexisting procedures, it shall provide a detailed description of its plan for acquiring ROW and land and managing ROW and land acquisition.

(M) The Interested TSP's preexisting procedures and historical practices for mitigating the impact of transmission facilities on affected landowners and for addressing public concerns regarding transmission facilities. If the Interested TSP does not have such preexisting procedures, it shall provide a detailed description of its plan for mitigating the impacts on affected landowners and addressing public concerns regarding CTP Facilities.

(N) A proposed financial plan that confirms that:

(i) adequate capital resources are available to the Interested TSP to allow the Interested TSP to finance the CTP Facilities, and

(ii) no significant negative impact on the creditworthiness or financial condition of the Interested TSP, as demonstrated in paragraphs (2)(A)-(D) of this subsection, will occur as a result of the Interested TSP's construction, operation, and maintenance of the CTP Facilities. In evaluating an Interested TSP's financial plan the commission will consider the terms of the proposed financing available to the Interested TSP including variable and fixed cost financing, short-term and long-term maturities and an Interested TSP's willingness and ability to fix the cost of financing for a fixed period of time.

(O) An affidavit by an officer of the Interested TSP stating that the information in the application is true and that the Interested TSP will comply with the applicable rules in this title and with the Public Utility Regulatory Act (PURA).

(P) Other evidence, at the discretion of the Interested TSP, which supports its selection as a Designated TSP.

(Q) Unless the Interested TSP is an electric cooperative or municipally owned utility, a description of the Interested TSP's use of historically underutilized businesses for the last five calendar years and expected use of historically underutilized businesses.

(R) Subparagraphs (A) through (N) of this paragraph do not apply to a CTP Proposal that is supported or unopposed by all parties in the proceeding by the deadline to file the CTP Proposal.

(2) The Interested TSP must establish that it has adequate financial resources as described in subparagraphs (A)-(G) of this paragraph.

(A) The Interested TSP holds a CCN issued by the commission for electric transmission facilities, or the Interested TSP holds a CCN issued by the commission to provide retail electric service and operates electric transmission facilities in Texas;

(B) The Interested TSP or its parent company or controlling shareholder or another company providing a bond guaranty or corporate commitment to the Interested TSP under subparagraph (E) of this paragraph must demonstrate an investment-grade credit rating as defined in subparagraph (E) of this paragraph; or

(C) The Interested TSP must establish that it has:

(i) assets less any goodwill but including regulatory assets in excess of liabilities of at least 40% of the projected total cost of the CTP Facility on its most recent audited financial statements; and

(ii) the following minimum financial ratios, adjusted to exclude transition bonds of subsidiaries, obtained from the Interested TSP's most recent audited financial statements:

(I) funds from operations-to-interest coverage of 1.5x;

(II) funds from operations-to-total debt of 10%; and

(III) total debt-to-total capital no greater than 65%.

However, the commission may choose not to require compliance with the minimum financial ratios if the Interested TSP cannot meet them because of non-recurring events that are projected to be favorable to ratepayers and the Interested TSP's long-term operations and financial condition, such as a large asset addition to its rate base.

(D) Notwithstanding subparagraphs (A)-(C) of this paragraph, the commission may determine that an Interested TSP is eligible for selection as a Designated TSP if the Interested TSP provides evidence satisfactory to the commission that it has the capability to finance the proposed CTP Facility it proposes to construct, operate, and maintain.

(E) For an Interested TSP to establish its investment-grade credit rating, it may rely upon its own investment-grade credit rating or a bond, guaranty, or corporate commitment of an investment-grade rated company. The determination of such investment-grade quality will be based on the credit ratings provided by Standard & Poor's (S&P), Moody's Investor Services (Moody's), or any other nationally recognized rating agency. The minimum investment credit ratings that will satisfy the requirements of this paragraph include "BBB-" for S&P, "Baa3" for Moody's, or their financial equivalent. If the relied-upon rating agency suspends or withdraws the investment grade credit rating, the Interested TSP shall provide alternative financial evidence within ten days of such suspension or withdrawal.

(F) To the extent an Interested TSP is an electric utility as defined in PURA §31.002(6) and relies on an affiliated transmission and distribution utility for credit, investment, or other financing arrangements, it shall demonstrate that any such arrangement complies with §25.272(d)(7) of this title (relating to Code of Conduct for Electric Utilities and their Affiliates).

(G) The Interested TSP shall provide a summary of any history of bankruptcy, dissolution, merger, or acquisition of the Interested TSP or any predecessors in interest for the current calendar year and the five calendar years immediately preceding its filing under this subsection (d)(1) of this section.

(f) **Performance of Designated TSP.**

(1) If the commission determines that a Designated TSP has failed to submit a CCN application in compliance with the order designating it for a CTP Facility, the commission may revoke the designation awarded to it, and select another entity for the CTP Facility.

(2) Within six months of the date the commission grants the CCN for CTP Facilities, the Designated TSP shall, based on the latest available information, file with the commission the following information.

(A) The estimated total cost for each CTP Facility in the following categories:

(i) CCN acquisition;

(ii) ROW and land acquisition;

(iii) engineering and design;

(iv) procurement of material and equipment; and

(v) construction of facilities.

(B) An implementation schedule for each CTP Facility that provides start and completion dates for the following four major functions:

(i) engineering and design;

(ii) ROW and land acquisition;

(iii) material and equipment procurement; and

(iv) construction of facilities.

The implementation schedule shall also include the estimated in-service date of the CTP Facilities.

(3) During implementation of each CTP Facility, the Designated TSP shall, within 30 days of becoming aware of any implementation schedule change that is greater than 60 days for the estimated dates provided pursuant to paragraph (2)(B) of this subsection, file with the commission a detailed explanation of the reasons for the change.

(4) If the commission determines that the Designated TSP has failed to comply with the CCN order for the CTP Facility, the commission may revoke the CCN.

(5) Each Designated TSP shall file an updated total cost for each of its CTP Facilities requiring a CCN, one year after CCN approval and annually thereafter until the CTP Facility is placed in-service.

(g) **Filing requirements.**

(1) Notwithstanding §25.174(c)(4) of this title, the commission may establish and amend a filing schedule for the submission of CCN applications for CTP Facilities.

(2) A Designated TSP shall use the commission form entitled “Application for a Certificate of Convenience and Necessity for a Proposed Transmission Line Pursuant to P.U.C. Subst. R. 25.174” when filing a CCN application for a CTP Facility.

(3) A Designated TSP filing a CCN application for a CTP Facility shall also file all direct testimony in support of the application at the time the application is filed.

§25.217. Distributed Renewable Generation.

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

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

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

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

(3) **Independent school district solar generation (ISD-SG)** -- Solar electric generation equipment installed on the customer's side of the meter at a building or other facility owned or operated by an independent school district, irrespective of the level of generation capacity.

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

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

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

(c) **Interconnection**.

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

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

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

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

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

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

(4) An existing or prospective DRGO or ISD-SG Owner may request interconnection by submitting an application for interconnection with the electric utility. The application shall be on a form

approved by the commission and processed by the electric utility in accordance with §25.211 and §25.212 of this title.

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

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

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

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

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

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

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

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

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

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

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

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

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

§25.221. Electric Cost Separation.

(a) **Purpose.** The purpose of this section is to identify the costs incurred by electric utilities that provide retail electric utility service, and to separate such costs into four categories: generation service, transmission service, distribution service, and customer service. This section establishes procedures for cost separation.

(b) **Application.** This section shall apply to electric utilities that provide retail electric service in Texas. This section shall not apply to municipal utilities.

(c) **Definitions.** As used in this section, the following terms have the following meanings unless the context clearly indicates otherwise:

(1) **Affected utilities** — shall refer to all utilities to which this section applies.

(2) **Customer service —** A service that consists of metering, billing, tariff administration, energy service, and related services. Customer service does not include generation service, transmission service, or distribution service; however, it does include all retail customer interaction necessary for the administration of tariffs that include charges for generation service, transmission service, and distribution service.

(3) **Distribution service —** A service that ensures safe and reliable delivery of electric power from the transmission system to retail customers, generally, but not exclusively, below 60 kilovolts. Distribution service does not include generation service, transmission service, or customer service.

(4) **Generation service** — The production and purchase of electricity for retail customers and the production, purchase, and sale of electricity in the wholesale power market.

(5) **Transmission service** — As defined in §25.5 of this title (relating to Definitions). For the purpose of this section, ancillary service, as defined in §25.5 of this title, is a component of transmission service.

(6) **Working day** — A day on which the commission is open for the conduct of business.

(d) **Cost separation.** Affected utilities shall maintain a cost-accounting and records system based on the Federal Energy Regulatory Commission chart of accounts system, as it may be updated, to ensure that the costs associated with generation service, transmission service, distribution service, and customer service are accurately and separately identified. Affected utilities shall create and maintain any additional accounts necessary to identify and separate costs incurred to provide retail electric utility service. Within the customer service category, the utility shall separate its costs on its books in sufficient detail to track costs specific to unique services, activities, or functions. The commission may adopt cost separation guidelines to assist affected utilities in separating their costs.

(e) **Compliance filing.**

(1) Affected utilities shall report to the commission on strategies to comply with the cost separation requirements of this section in accordance with the commission cost separation guidelines. The filing shall provide a narrative that discusses the types of distribution and customer service costs and activities that the utility will begin to track separately to comply with this section. The narrative shall explain the changes needed in accounting procedures, activity tracking, timekeeping, and other management functions necessary to track the newly segregated costs, including a list that identifies costs that the utility will begin to track separately.

(2) **Compliance filing date**. Affected utilities shall make a compliance filing according to the following schedule:

(A) Investor-owned electric utilities shall file by December 31, 1998.

(B) All other affected utilities shall file by December 31, 1999.

§25.223. Unbundling of Energy Service.

(a) **Purpose.** The purpose of this section is to identify all energy services, and determine which energy services must be provided by tariff and which energy services are currently provided in competition with non-utility suppliers. This section also allows the commission to set forth the terms and conditions for public access to non-proprietary utility information.

(b) **Application**. This section applies to electric utilities that provide retail electric service in Texas. This section does not apply to municipal utilities.

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

(1) **Accessible utility information** — Information compiled by an affected utility during the normal course of providing electric service. This includes, but is not limited to, information used to prepare electric tariffs, to provide electric service to customers, or to market, sell, or demonstrate any electric or energy-related service or product. Accessible utility information does not include:

(A) administrative information necessary for the operation of the affected utility;

(B) proprietary customer information;

(C) trade secrets; or

(D) information that the affected utility demonstrates is competitively sensitive.

(2) **Affected utilities** — Refers to all utilities to which this section applies.

(3) **Customer service** — As defined in §25.221 of this title (relating to Electric Cost Separation).

(4) **Distribution service** — As defined in §25.221 of this title (relating to Electric Cost Separation).

(5) **Energy service** — A service provided by an affected utility that is related to the provision of electric service by the affected utility. Energy service may be a component of either customer service or distribution service, or may be a separate, competitively-available service. Energy service includes, but is not limited to:

(A) explanation of tariff options and determination of the appropriate rate schedule for a retail customer and related software and services;

(B) administration of commission-authorized demand-side resource contracts;

(C) administration of commission-authorized low-income programs and activities;

(D) sale, financing, installation, operation, warranty, or repair of energy-consuming, customer-premise equipment;

(E) the provision of energy efficiency and load management services;

(F) the provision of technical assistance relating to any customer-premises process or device that consumes electricity, including energy audits;

(G) sale, financing, installation, operation, warranty, or repair of customer-premises power quality and reliability equipment and related diagnostic services;

(H) the provision of anything of value to trade groups, builders, developers, financial institutions, architects and engineers, landlords, and other persons involved in making decisions relating to investments in energy-consuming equipment or buildings on behalf of the ultimate retail electricity customer;

(I) sale, financing, installation, operation, warranty, or repair of customer-premises power-generation equipment and related services;

(J) the provision of information relating to customer usage other than as required for the rendering of a monthly electric bill, including electrical pulse service;

(K) communications services related to any energy service not essential for the retail sale of electricity;
(L) home and property security services;
(M) non-roadway, outdoor security lighting;
(N) building or facility design and related engineering services, or analysis and design of energy-related industrial processes;
(O) hedging and risk management services;
(P) propane and other energy-based services;
(Q) retail marketing, selling, demonstration, and merchant activities;
(R) customer education, including school programs and community education activities;
(S) advertising, including safety advertising;
(T) economic development and community affairs; and
(U) other activities identified by the commission.

(6) **Proprietary customer information —** Any information compiled by an electric utility on a customer in the normal course of providing electric service which makes possible the identification of any individual customer by matching such information with the customer's name, address, account number, type or classification of service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges, billing records, or any other information that the customer has expressly requested not be disclosed. Information that is aggregated, redacted, or organized in such a way as to make it impossible to identify the customer to whom the information relates does not constitute proprietary customer information.

(d) **Review of energy services**. The commission will review the energy services of affected utilities through the filing procedures set forth in this section.

(e) **Accessible utility information**. All affected utilities shall make accessible utility information available on the following terms:

(1) **Public access**. Affected utilities shall file service regulations that allow non-discriminatory public access to accessible utility information. The service regulations shall describe the information, available formats, procedures for obtaining access, and the charges, if any, for accessing this information. The service regulations shall comply with the confidentiality and disclosure protections of this section. Individual customer information shall be eliminated from the data as necessary to comply with this section, and customer information shall be aggregated only to the extent necessary to protect proprietary customer information, except where a customer has waived in writing the protection of proprietary customer information.

(2) **Access plan**. Affected utilities shall submit to the commission a plan relating to the creation and maintenance of accessible utility information. The plan shall indicate the utility operating unit responsible for the information, the access required by other operating units, the type of information to be maintained, and the type of information to be created and maintained in the future. The utility shall indicate whether any accessible utility information has been destroyed during the past three years.

(3) **Historic information**. Information relating to the period prior to the effective date of this section shall include a description of the information and the year to which it relates. Such information shall be made available according to the following schedule:

(A) Non-customer-specific load-research data, hourly-load-profile data, appliance- and equipment-saturation surveys, and market surveys shall be made available within 60 days of the effective date of this section. This subparagraph applies to the most recent data of each type.

(B) All other accessible utility information shall be made available upon request.

(4) **New information**. Accessible utility information collected subsequent to the effective date of this section shall be described in separate service regulations. Internet accessibility is encouraged to provide equal access to the other operating units of the affected utility, to interested persons, and to affiliates of the utility.

(5) **Protection of information**. This section does not require a utility to divulge competitively-sensitive information, proprietary customer information, corporate support service information, or trade secrets.

(f) **Filing**. Affected utilities shall file descriptions of the energy services provided by the utility on forms provided by the commission, their plan for accessible utility information, and any new service regulations relating to accessible utility information. The commission shall review these materials and notify the utility of acceptance within 120 days. Affected utilities shall make a filing for this section according to the following schedule:

(1) Affected utilities with more than one million meters on the effective date of this rule and any electric utility affiliated with such utilities shall file within 30 days of the effective date of this section.

(2) Affected utilities with more than 100,000 meters but fewer than one million meters on the effective date of this rule and any electric utility affiliated with such utilities shall file within 45 days of the effective date of this section.

(3) All other affected utilities shall file within 60 days of the effective date of this section.

§25.227. Electric Utility Service for Public Retail Customers.

(a) **Purpose.** The purpose of this section is to establish the terms under which the General Land Office may take utility service, including transmission, distribution, and customer services, in order to convey power to public retail customers purchased under the Public Utility Regulatory Act (PURA) §35.102. This section also allows public retail customers the option to purchase power from the General Land Office. This section requires electric utilities, and municipally owned utilities and electric cooperatives that have adopted customer choice, to file tariffs to specify the terms and conditions under which the General Land Office may take utility service from an affected utility pursuant to PURA §35.103(b). These tariffs must include any stranded costs associated with providing the service.

(b) **Application.** This section shall apply to electric utilities that provide retail electric service in Texas, and municipally owned electric utilities and electric cooperatives that have adopted customer choice. This section shall not apply to either municipally owned electric utilities or to electric cooperatives that have not adopted customer choice. In a certificated area of an electric utility in which customer choice has not been introduced, the General Land Office may not engage in retail transactions that exceed 2.5% of a retail electric utility's total retail load, calculated based on the system peak for the calendar year 1998.

(c) **Definitions.** As used in this section, the following terms have the following meanings unless the context clearly indicates otherwise:

(1) **Affected utilities** – shall refer to all utilities as defined in subsection (b) of this section.

(2) **Customer service –** As defined in §25.221 of this title (relating to Electric Cost Separation).

(3) **Distribution service** – As defined in §25.221 of this title (relating to Electric Cost Separation)

(4) **Transmission service** – As defined in §25.221 of this title (relating to Electric Cost Separation).

(5) **Public retail customer –** A retail customer that is an agency of this state as defined in §25.78 of this title (relating to State Agency Utility Account Information), a state institution of higher education, a public school district, or a political subdivision of this state. Under Texas Government Code §447.008(d), a state agency or institution of higher education may request assistance from the Office of the Attorney General in the negotiating rates and terms of electric service .

(6) **Stranded cost** – The amount estimated by the commission in the scenario which assumes retail access beginning in the year 2002, "base" market prices, and including the effects of cost benchmarking and transition plans where applicable, in the "Potentially Strandable Investment (ECOM) Report: 1998 Update," as described in PURA §39.262(i).

(7) **Functional percentage –** The ratio of each of the transmission, distribution, and customer service costs to total costs for each rate class of each utility, as identified in Appendix F of the Staff Report filed in Project Number 20749, *Functional Cost Separation of Electric Utilities in Texas*.

(d) **Obligations of affected utilities.**

(1) Each affected utility is obligated to provide the services prescribed by this section on a comparable and non-discriminatory basis, and under the same terms and conditions for service to similarly situated customers.

(2) Each affected utility's obligations shall include, but are not limited to, the obligation to extend electric service to new locations.

(3) The affected utility shall provide to the General Land Office within three business days of collection all demand and/or energy consumption readings applicable to each public retail customer to which

the General Land Office conveys power. This information is subject to any protections of the Public Information Act, Texas Government Code, Chapter 552.

(e) **Filing requirements.**

(1) Upon a request for service pursuant to this section by the General Land Office, an affected utility shall file a tariff to implement the provisions of this section not later than 15 days from the date of the request. The proposed tariffs of electric utilities shall comply with subsection (f) of this section, and with the commission's standard tariff format for this section. As part of this filing, electric utilities shall provide all supporting workpapers and documents used in the calculation of the power delivery charge and the competition transition charge.

(2) The commission shall approve or deny a proposed tariff filed by an electric utility under this section within 30 days of filing. A proposed tariff may be approved on an interim basis, subject to refund or surcharge, prior to final approval.

(f) **Tariff requirements.** Each tariff of an electric utility shall contain the following provisions listed in paragraphs (1) through (8) of this subsection. Paragraph (8) of this subsection shall apply to all affected utilities as defined in subsection (b) of this section.

(1) **Power delivery charge**. The sum of the transmission, distribution, and customer services charges established under this section. No credits shall be made to the power delivery charge, except for credits related to transmission-level service and billing and customer service, as provided in paragraphs (5) and (6) of this subsection.

(2) **Transmission charge.** A charge for transmission service as established in subsection (h) of this section. A separate charge shall be listed for each rate class.

(3) **Distribution charge.** A charge for distribution service as established in subsection (h) of this section. A separate charge shall be listed for each rate class.

(4) **Customer service charge.** A charge for retail customer service equal to the sum of the metering and billing and the tariff administration, energy services, and other customer service charges as established in subsection (h) of this section. A separate charge shall be listed for each rate class.

(5) **Transmission-level service credit.** A credit equal to the distribution charge, to be applied to the power delivery charge for public retail customers that take electric service at transmission voltage. This credit shall apply only in the event an affected utility does not have a commission-approved tariff for electric service at transmission voltage.

(6) **Billing and customer service credit.** A credit equal to the tariff administration, energy services, and other customer services portion of the customer service rate, which shall be applied to the power delivery charge if the affected utility does not bill the public retail customer directly on behalf of the General Land Office.

(7) **Competition transition charge**. A charge as established in subsection (g) of this section for the recovery of stranded costs associated with providing the service.

(8) **Terms and conditions**. Terms and conditions shall be consistent with the existing bundled rate tariffs.

(g) **Competition transition charge (CTC)**

(1) The competition transition charge for an electric utility shall be calculated as follows:

(A) The stranded costs for each utility shall be amortized over the average remaining life of the generation asset(s) underlying the stranded costs, and shall be allocated to each class pursuant to the method prescribed by PURA §39.253;

(B) The rate design of the CTC for each class shall be consistent with the rate design used to recover the costs of the generation assets underlying the stranded costs in the utility's last rate proceeding, calculated to reflect billing determinants for the year ending April 30, 1999, adjusted for normal weather.

(2) The CTC calculated pursuant to this section shall remain in effect until replaced by the CTC established pursuant to PURA §39.201. The CTC shall include a reasonable return for the years 2000 and 2001 on the unrecovered balance of stranded costs. The year 2000 balance shall be its January 1, 2002 balance discounted at 8.5% per year for each of the years 2000 and 2001. Such return shall be as identified in PURA §39.258(7).

(3) The CTC calculated pursuant to this section shall be subject to PURA §39.262, True-Up Proceeding.

(h) **Rate design for electric utilities.**

(1) The functional percentages determined for each rate class for each electric utility in Project Number 20749, *Functional Cost Separation of Electric Utilities in Texas*, shall be applied to each component of the existing bundled rate. The existing rate structure shall be maintained.

(2) The rate design required by this section for electric utilities shall remain in effect until replaced by the rate design established pursuant to PURA §39.201.

(3) An affected utility that is not subject to PURA Chapter 39, pursuant to §39.102(c), may request and the commission may grant, a one-time revision of the functional percentages determined for each rate class of that utility in Project Number 20749. The revision shall be based on actual cost data for the year ending December 31, 2001.

§25.231. Cost of Service.

(a) **Components of cost of service.** Except as provided for in subsection (c)(2) of this section, relating to invested capital; rate base, and §23.23(b) of this title, (relating to Rate Design), rates are to be based upon an electric utility's cost of rendering service to the public during a historical test year, adjusted for known and measurable changes. The two components of cost of service are allowable expenses and return on invested capital.

(b) **Allowable expenses.** Only those expenses which are reasonable and necessary to provide service to the public shall be included in allowable expenses. In computing an electric utility's allowable expenses, only the electric utility's historical test year expenses as adjusted for known and measurable changes will be considered, except as provided for in any section of these rules dealing with fuel expenses.

(1) **Components of allowable expenses.** Allowable expenses, to the extent they are reasonable and necessary, and subject to this section, may include, but are not limited to the following general categories:

(A) Operations and maintenance expense incurred in furnishing normal electric utility service and in maintaining electric utility plant used by and useful to the electric utility in providing such service to the public. Payments to affiliated interests for costs of service, or any property, right or thing, or for interest expense shall not be allowed as an expense for cost of service except as provided in the Public Utility Regulatory Act §36.058.

(B) Depreciation expense based on original cost and computed on a straight line basis as approved by the commission. Other methods of depreciation may be used when it is determined that such depreciation methodology is a more equitable means of recovering the cost of the plant.

(C) Assessments and taxes other than income taxes.

(D) Federal income taxes on a normalized basis. Federal income taxes shall be computed according to the provisions of the Public Utility Regulatory Act §36.060.

(E) Advertising, contributions and donations. The actual expenditures for ordinary advertising, contributions, and donations may be allowed as a cost of service provided that the total sum of all such items allowed in the cost of service shall not exceed three-tenths of 1.0% (0.3%) of the gross receipts of the electric utility for services rendered to the public. The following expenses shall be included in the calculation of the three-tenths of 1.0% (0.3%) maximum:

(i) funds expended advertising methods of conserving energy;

(ii) funds expended advertising methods by which the consumer can effect a savings in total electric utility bills;

(iii) funds expended advertising methods to shift usage off of system peak; and

(iv) funds expended promoting renewable energy.

(F) Nuclear decommissioning expense. The following restrictions shall apply to the inclusion of nuclear decommissioning costs that are placed in an electric utility's cost of service.

(i) An electric utility owning or leasing an interest in a nuclear-fueled generating unit shall include its cost of nuclear decommissioning in its cost of service. Funds collected from ratepayers for decommissioning shall be deposited monthly in irrevocable trusts external to the electric utility, in accordance with §25.301 of this title (relating to Nuclear Decommissioning Trusts). All funds held in short-term investments must bear interest. The level of the annual cost of decommissioning for ratemaking purposes will be determined in each rate case based on an allowance for contingencies of 10% of the cost of decommissioning, the most current information reasonably available regarding the cost of decommissioning, the balance of funds in the decommissioning trust, anticipated escalation rates, the anticipated return on the funds in the decommissioning trust, and other relevant factors. The annual amount for the cost of decommissioning determined pursuant to the preceding sentence shall be expressly included in the cost of service established by the commission's order.

(ii) In the event that an electric utility implements an interim rate increase, including an increase filed under bond, an incremental change in decommissioning funding shall be included in the increase.

(iii) An electric utility's decommissioning fund and trust balances will be reviewed in general rate cases. In the event that an electric utility does not have a rate case within a five-year period, the commission, on its own motion or on the motion of the commission's Office of Regulatory Affairs, the Office of Public Utility Counsel, or any affected person, may initiate a proceeding to review the electric utility's decommissioning cost study and plan, and the balance of the trust.

(iv) An electric utility shall perform, or cause to be performed, a study of the decommissioning costs of each nuclear generating unit that it owns or in which it leases an interest. A study or a redetermination of the previous study shall be performed at least every five years. The study or redetermination should consider the most current information reasonably available on the cost of decommissioning. A copy of the study or redetermination shall be filed with the commission and copies provided to the commission's Office of Regulatory Affairs and the Office of Public Utility Counsel. An electric utility's most recent decommissioning study or redeterminations shall be filed with the commission within 30 days of the effective date of this subsection. The five year requirement for a new study or redetermination shall begin from the date of the last study or redetermination.

(G) Accruals credited to reserve accounts for self-insurance under a plan requested by an electric utility and approved by the commission. The commission shall consider approval of a self insurance plan in a rate case in which expenses or rate base treatment are requested for a such a plan. For the purposes of this section, a self insurance plan is a plan providing for accruals to be credited to reserve accounts. The reserve accounts are to be charged with property and liability losses which occur, and which could not have been reasonably anticipated and included in operating and maintenance expenses, and are not paid or reimbursed by commercial insurance. The commission will approve a self insurance plan to the extent it finds it to be in the public interest. In order to establish that the plan is in the public interest, the electric utility must present a cost benefit analysis performed by a qualified independent insurance consultant who demonstrates that, with consideration of all costs, self-insurance is a lower-cost alternative than commercial insurance and the ratepayers will receive the benefits of the self insurance plan. The cost benefit analysis shall present a detailed analysis of the appropriate limits of self insurance, an analysis of the appropriate annual accruals to build a reserve account for self insurance, and the level at which further accruals should be decreased or terminated.

(H) Postretirement benefits other than pensions (known in the electric utility industry as "OPEB"). For ratemaking purposes, expense associated postretirement benefits other than pensions (OPEB) shall be treated as follows:

(i) OPEB expense shall be included in an electric utility's cost of service for ratemaking purposes based on actual payments made.

(ii) An electric utility may request a one-time conversion to inclusion of current OPEB expense in cost of service for ratemaking purposes on an accrual basis in accordance with generally accepted accounting principles (GAAP). Rate recognition of OPEB expense on an accrual basis shall be made only in the context of a full rate case.

(iii) An electric utility shall not be allowed to recover current OPEB expense on an accrual basis until GAAP requires that electric utility to report OPEB expense on an accrual basis.

(iv) For ratemaking purposes, the transition obligation shall be amortized over 20 years.

(v) OPEB amounts included in rates shall be placed in an irrevocable external trust fund dedicated to the payment of OPEB expenses. The trust shall be established no later than six months after the order establishing the OPEB expense amount included in rates. The electric utility shall make deposits to the fund at least once per year. Deposits on the fund shall include, in addition to the amount included in rates, an amount equal to fund earnings that would have accrued if deposits had been made monthly. The funding requirement can be met with deposits made in advance of the recognition of the expense for ratemaking purposes. The electric utility shall, to the extent permitted by the Internal Revenue Code, establish a postretirement benefit plan that allows for current federal income tax deductions for contributions and allows earnings on the trust funds to accumulate tax free.

(vi) When an electric utility terminates an OPEB trust fund established pursuant to clause (v) of this subparagraph, it shall notify the commission in writing. If excess assets remain after the OPEB trust fund is terminated and all trust related liabilities are satisfied, the electric utility shall file, for commission approval, a proposed plan for the distribution of the excess assets. The electric utility shall not distribute any excess assets until the commission approves the disbursement plan.

(2) **Expenses not allowed.** The following expenses shall never be allowed as a component of cost of service:

(A) legislative advocacy expenses, whether made directly or indirectly, including, but not limited to, legislative advocacy expenses included in professional or trade association dues;

(B) funds expended in support of political candidates;

(C) funds expended in support of any political movement;

(D) funds expended promoting political or religious causes;

(E) funds expended in support of or membership in social, recreational, fraternal, or religious clubs or organizations;

(F) funds promoting increased consumption of electricity;

(G) additional funds expended to mail any parcel or letter containing any of the items mentioned in subparagraphs (A)-(F) of this paragraph;

(H) payments, except those made under an insurance or risk-sharing arrangement executed before the date of the loss, made to cover costs of an accident, equipment failure, or negligence at an electric utility facility owned by a person or governmental body not selling power within the State of Texas;

(I) costs, including, but not limited to, interest expense, of processing a refund or credit of sums collected in excess of the rate finally ordered by the commission in a case where the electric utility has put bonded rates into effect, or when the electric utility has otherwise been ordered to make refunds;

(J) any expenditure found by the commission to be unreasonable, unnecessary, or not in the public interest, including but not limited to executive salaries, advertising expenses, legal expenses, penalties and interest on overdue taxes, criminal penalties or fines, and civil penalties or fines.

(c) **Return on invested capital.** The return on invested capital is the rate of return times invested capital.

(1) **Rate of return.** The commission shall allow each electric utility a reasonable opportunity to earn a reasonable rate of return, which is expressed as a percentage of invested capital, and shall fix the rate of return in accordance with the following principles.

(A) The return should be reasonably sufficient to assure confidence in the financial soundness of the electric utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low because of changes affecting opportunities for investment, the money market, and business conditions generally.

(B) The commission shall consider efforts by the electric utility to comply with the statewide integrated resource plan, the efforts and achievements of the electric utility in the conservation of resources, the quality of the electric utility's services, the efficiency of the electric utility's operations, and the quality of the electric utility's management, along with other applicable conditions and practices.

(C) The commission may, in addition, consider inflation, deflation, the growth rate of the service area, and the need for the electric utility to attract new capital. The rate of return must be high enough to attract necessary capital but need not go beyond that. In each case, the commission shall consider the electric utility's cost of capital, which is the weighted average of the costs of the various classes of capital used by the electric utility.

(i) Debt capital. The cost of debt capital is the actual cost of debt at the time of issuance, plus adjustments for premiums, discounts, and refunding and issuance costs.

(ii) Equity capital. For companies with ownership expressed in terms of shares of stock, equity capital commonly consists of the following classes of stock.

(I) Common stock capital. The cost of common stock capital shall be based upon a fair return on its market value.

(II) Preferred stock capital. The cost of preferred stock capital is the actual cost of preferred stock at the time of issuance, plus an adjustment for premiums, discounts, and refunding and issuance costs.

(2) **Invested capital; rate base.** The rate of return is applied to the rate base. The rate base, sometimes referred to as invested capital, includes as a major component the original cost of plant, property, and equipment, less accumulated depreciation, used and useful in rendering service to the public. Components to be included in determining the overall rate base are as set out in subparagraphs (A)-(F) of this paragraph.

(A) Original cost, less accumulated depreciation, of electric utility plant used by and useful to the electric utility in providing service.

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

(ii) Reserve for depreciation is the accumulation of recognized allocations of original cost, representing recovery of initial investment, over the estimated useful life of the asset. Depreciation shall be computed on a straight line basis or by such other method approved under subsection (b)(1)(B) of this section over the expected useful life of the item or facility.

(iii) Payments to affiliated interests shall not be allowed as a capital cost except as provided in the Public Utility Regulatory Act §36.058.

(B) Working capital allowance to be composed of, but not limited to the following:

(i) Reasonable inventories of materials, supplies, and fuel held specifically for purposes of permitting efficient operation of the electric utility in providing normal electric utility service. This amount excludes appliance inventories and inventories found by the commission to be unreasonable, excessive, or not in the public interest.

(ii) Reasonable prepayments for operating expenses. Prepayments to affiliated interests shall be subject to the standards set forth in the Public Utility Regulatory §36.058.

(iii) A reasonable allowance for cash working capital. The following shall apply in determining the amount to be included in invested capital for cash working capital:

(I) Cash working capital for electric utilities shall in no event be greater than one-eighth of total annual operations and maintenance expense, excluding amounts charged to operations and maintenance expense for materials, supplies, fuel, and prepayments.

(II) For electric cooperatives, river authorities, and investor-owned electric utilities that purchase 100% of their power requirements, one-eighth of operations and maintenance expense excluding amounts charged to operations and maintenance expense for materials, supplies, fuel, and prepayments will be considered a reasonable allowance for cash working capital.

(III) Operations and maintenance expense does not include depreciation, other taxes, or federal income taxes, for purposes of subclauses (I), (II), and (V)of this clause.

(IV) For all investor-owned electric utilities a reasonable allowance for cash working capital, including a request of zero, will be determined by the use of a lead-lag study. A lead-lag study will be performed in accordance with the following criteria:

(-a-) The lead-lag study will use the cash method; all non-cash items, including but not limited to depreciation, amortization, deferred taxes, prepaid items, and return (including interest on long-term debt and dividends on preferred stock), will not be considered.

(-b-) Any reasonable sampling method that is shown to be unbiased may be used in performing the lead-lag study.

(-c-) The check clear date, or the invoice due date, whichever is later, will be used in calculating the lead-lag days used in the study. In those cases where multiple due dates and payment terms are offered by vendors, the invoice due date is the date corresponding to the terms accepted by the electric utility.

(-d-) All funds received by the electric utility except electronic transfers shall be considered available for use no later than the business day following the receipt of the funds in any repository of the electric utility (e.g. lockbox, post office box, branch office). All funds received by electronic transfer will be considered available the day of receipt.

(-e-) For electric utilities the balance of cash and working funds included in the working cash allowance calculation shall consist of the average daily bank balance of all non-interest bearing demand deposits and working cash funds.

(-f-) The lead on federal income tax expense shall be calculated by measurement of the interval between the mid-point of the annual service period and the actual payment date of the electric utility.

(-g-) If the cash working capital calculation results in a negative amount, the negative amount shall be included in rate base.

(V) If cash working capital is required to be determined by the use of a lead-lag study under the previous subclause and either the electric utility does not file a lead lag study or the electric utility's lead-lag study is determined to be so flawed as to be unreliable, in the absence of persuasive evidence that suggests a different amount of cash working capital, an amount of cash working capital equal to negative one-eighth of operations and maintenance expense including fuel and purchased power will be presumed to be the reasonable level of cash working capital.

(C) Deduction of certain items which include, but are not limited to, the following:

(i) accumulated reserve for deferred federal income taxes;

(ii) unamortized investment tax credit to the extent allowed by the Internal Revenue Code;

(iii) contingency and/or property insurance reserves;

(iv) contributions in aid of construction;

(v) customer deposits and other sources of cost-free capital;

(D) Construction work in progress (CWIP). The inclusion of construction work in progress is an exceptional form of rate relief. Under ordinary circumstances the rate base shall consist only of those items which are used and useful in providing service to the public. Under exceptional circumstances, the commission will include construction work in progress in rate base to the extent that:

(i) the electric utility has proven that:

(I) the inclusion is necessary to the financial integrity of the electric utility; and

(II) major projects under construction have been efficiently and prudently planned and managed. However, construction work in progress shall not be allowed for any portion of a major project which the electric utility has failed to prove was efficiently and prudently planned and managed; or

(ii) for a project ordered by the commission under §25.199 of this title (relating to Transmission Planning, Licensing and Cost-recovery for Utilities within the Electric Reliability Council of Texas), if the commission determines that conditions warrant the inclusion of CWIP in rate base, the project is being efficiently and prudently planned and managed, and there will be a significant delay between initial investment and the initial cost recovery for a transmission project.

(E) Self-insurance reserve accounts. If a self insurance plan is approved by the commission, any shortages to the reserve account will be an increase to the rate base and any surpluses will be a decrease to the rate base. The electric utility shall maintain appropriate books and records to permit the commission to properly review all charges to the reserve account and determine whether the charges being booked to the reserve account are reasonable and correct.

(F) Requirements for post test year adjustments.

(i) Post test year adjustments for known and measurable rate base additions (increases) to historical test year data will be considered only as set out in subclauses (I)-(IV) of this clause.

(I) Where the addition represents plant which would appropriately be recorded:

(-a-) for investor-owned electric utilities in FERC account 101 or 102;

(-b-) for electric cooperatives, the equivalent of FERC accounts 101 or 102.

(II) Where each addition comprises at least 10% of the electric utility's requested rate base, exclusive of post test year adjustments and CWIP.

(III) Where the plant addition is deemed by this commission to be in-service before the rate year begins.

(IV) Where the attendant impacts on all aspects of a utility's operations (including but not limited to, revenue, expenses and invested capital) can with reasonable certainty be identified, quantified and matched. Attendant impacts are those that reasonably follow as a consequence of the post test year adjustment being proposed.

(ii) Each post test year plant adjustment will be included in rate base at:

(I) the reasonable test year-end CWIP balance, if the addition is constructed by the electric utility; or,

(II) the reasonable price, if the addition represents a purchase, subject to original cost requirements, as specified in Public Utility Regulatory Act §36.053.

(iii) Post test year adjustments for known and measurable rate base decreases to historical test year data will be allowed only when clause (i)(IV) of this subparagraph and the criteria described in subclauses (I) and (II) of this clause are satisfied.

(I) The decrease represents:

(-a-) plant which was appropriately recorded in the accounts set forth in clause (i)(I) of this subparagraph;

(-b-) plant held for future use;

(-c-) CWIP (mirror CWIP is not considered CWIP); or

(-d-) an attendant impact of another post test year adjustment.

(II) Plant that has been removed from service, mothballed, sold, or removed from the electric utility's books prior to the rate year.

DIVISION 1. RETAIL RATES.

§25.232. Adjustment for House Bill 11, Acts of 72nd Legislature, First Called Special Session 1991.

(a) Each electric utility that is subject to the commission's rate setting jurisdiction, pays state franchise taxes, and has not had a rate proceeding under the Public Utility Regulatory Act §36.103 and §36.151, in which the effects of House Bill 11 were considered when setting the rates, shall be subject to this subsection. Except as provided in the following sentence, on or before December 1 of each year, each electric utility subject to this subsection shall file with the commission a tariff sheet, or tariff sheets, applicable to each rate class setting forth an interim House Bill 11 tax adjustment factor. If an electric utility chooses not to request an increase under this subsection or if the electric utility has otherwise limited itself by agreement to recovering tax changes that are the subject of this subsection by a method different from that prescribed in this subsection, the electric utility need not file tariff sheets but shall make an informational filing showing its calculations, including an explanation and all underlying supporting documentation showing the effect of House Bill 11 on its taxes. If the adjustment is a decrease that amounts to less than $1.00 per customer for electric utilities on an annual basis, the tariff shall not include a factor, but shall state that the reduction will be applied against the adjustment for future years. In all other tariffs, the factors set forth in the tariff sheets shall be calculated as set forth in the following paragraphs. Electric utilities that are required to file tariff sheets shall include an explanation of how the interim factor was calculated and showing all the calculations.

(b) If the adjustment is a decrease requiring a factor, or the electric utility affirmatively requests that an adjustment be made to its billings to account for the effect of House Bill 11 on its state taxes, the tariff filing will be docketed and will automatically go into effect on January 1 of the year following the filing. If the adjustment is a decrease being carried forward to future years, the filing will be treated as a tariff filing except that it shall take effect on January 1 of the year following the filing. An electric utility may amend a tariff filed under this subsection to make mid-course corrections as necessary. For all amended filings, all tariffs will take effect on the date specified by the electric utility, but in no event earlier than ten days after the filing.

(c) The interim House Bill 11 tax adjustment factor shall be calculated by allocating the effect on the electric utility's state taxes for the next calendar year of House Bill 11 as provided in subsection (f) of this section. The effect on the electric utility's state taxes for the coming calendar year shall be calculated by subtracting the estimated state taxes attributable to the calendar year if the law prior to House Bill 11 were still in effect, from the estimated state taxes due or attributable to the calendar year under House Bill 11. In calculating the state taxes that would be due during the calendar year if the law prior to House Bill 11 were still in effect, four-twelfths of the franchise tax paid or that would have been paid in the previous year and eight-twelfths of the franchise tax that would have been paid in the calendar year in question will be considered attributable to the calendar year in question. In performing the calculation, the various fees imposed by House Bill 11 will not be considered taxes. In calculating the taxes that are estimated to be paid, changes resulting from audits or amended returns for previous periods that were covered by this rule shall be considered. The state franchise tax imposed by House Bill 11 will be considered to be a franchise tax and not an income tax regardless of the method of calculation.

(d) If an interim factor goes into effect, it shall be subject to surcharge or refund to the extent it differs from the factor finally set by the commission. If a surcharge or refund is necessary, a credit or surcharge will be made to the existing customers' bills. If the refund or surcharge amount is less than either $10,000 in total or $1.00 per customer, calculated by dividing the total refund or surcharge by the total number of customers, the electric utility may make the refund or surcharge by carrying it forward until a year when the cumulative total refund or surcharge is not less than either $10,000 or $1.00 per customer. Simple interest will be added to the amount due at the rate set by the commission for overbillings and underbillings starting at the beginning of the month in which the obligation accrued and ending on the last day of the month preceding the refund or surcharge. The month, or months, in which the obligation accrues will be determined by comparing the collections each month under the tariff filed by the electric utility with the amount that should have been collected had the electric utility been able to precisely predict its tax bill and its sales. The number of days in each month shall be considered for purposes of the interest calculation. Interest will be added to decreases that are carried to future years and will be calculated by the same method.

(e) The electric utility shall file, on or before the first business day after March 1 of the year following the year when a particular factor was in effect, testimony supporting the final adjustment factor that it is requesting to account for the effect of House Bill 11 on its state taxes for that year. The electric utility's filing will include a copy of the Franchise Tax Return filed with the Comptroller's Office and the details of their computation of the tax that would have been due had House Bill 11 not been enacted. The hearing on the merits for purposes of setting the final factor, if necessary, shall be convened no earlier than 45 days after the filing of the electric utility's testimony and shall be strictly limited to issues under this subsection. For purposes of administrative efficiency, the presiding officer assigned to a case may grant an electric utility's request that the final hearing on a particular year's factor be delayed for up to three years; however, if such a request is granted, any interest to be paid by the electric utility shall be at the utility's cost of capital as determined in the electric utility's last rate case. Requests to delay the final hearing on a particular year's factor shall be filed with the testimony supporting the final adjustment factor.

(f) The billing adjustment should apply over the entire year; however, if the adjustment necessary to account for the effect of House Bill 11 is so small that it would be difficult to apply on a monthly basis, the electric utility may make the billing adjustment during a single month. Cost allocation and rate design are as follows.

(1) If the adjustment factor results in a lower cost to the ratepayers, the revenue decrease shall be allocated to the customers on the same basis as the franchise taxes were allocated in the electric utility's last rate case.

(2) If the adjustment factor results in a greater cost to the ratepayers, the revenue increase will be allocated to the customers in the same manner as were federal income taxes in the electric utility's last rate case.

(3) The factor for each customer within a class will then be calculated based on expected kilowatt-hour (kwh) sales and charged on a per kwh basis, except that the factor for each customer within an industrial class served at transmission-level voltage will be calculated as a percentage of the base revenues (excluding fuel, any applicable power cost recovery factor (PCRF) charges, and add-on revenue taxes) received from that class during the most recent 12-month period.

§25.234. Rate Design.

(a) Rates shall not be unreasonably preferential, prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to each class of customers, and shall be based on cost.

(b) Rates will be determined using revenues, billing and usage data for a historical test year adjusted for known and measurable changes, and costs of service as defined in §25.231 of this title (relating to Cost of Service).

§25.235. Fuel Costs — General.

(a) **Purpose.** The commission will set an electric utility's rates at a level that will permit the electric utility a reasonable opportunity to earn a reasonable return on its invested capital and to recover its reasonable and necessary expenses, including the cost of fuel and purchased power. The commission recognizes in this connection that it is in the interests of both electric utilities and their ratepayers to adjust charges in a timely manner to account for changes in certain fuel and purchased-power costs. Pursuant to the Public Utility Regulatory Act (PURA) §36.203 this section establishes a procedure for setting and revising fuel factors and a procedure for regularly reviewing the reasonableness of the fuel expenses recovered through fuel factors.

(b) **Notice of fuel proceedings.** In addition to the notice required by the Administrative Procedure Act (APA) to be given by the commission, the electric utility is required to give notice of a fuel proceeding at the time the petition is filed.

(1) **Method of notice.** Notice of fuel proceedings will be given by the electric utility as follows:

(A) Notice in all proceedings involving refunds, surcharges, or a proposal to change the fuel factor, shall be by one-time publication in a newspaper having general circulation in each county of the service area of the electric utility or by individual notice to each customer and by individual notice to parties that participated in the electric utility's prior fuel reconciliation proceeding;

(B) Notice in all reconciliation proceedings shall be by publication once each week for two consecutive weeks in a newspaper having general circulation in each county of the service area of the electric utility and by individual notice to each customer and to parties that participated in the electric utility's prior fuel reconciliation proceeding.

(2) **Contents of notice.**

(A) All notices required by this section shall provide the following information:

(i) the date the petition was filed;

(ii) a general description of the customers, customer classes, and territories affected by the petition;

(iii) the relief requested;

(iv) the statement, "Persons with questions or who want more information on this petition may contact (utility name) at (utility address) or call (utility toll-free telephone number) during normal business hours. A complete copy of this petition is available for inspection at the address listed above"; and

(v) the statement, "Persons who wish to formally participate in this proceeding , or who wish to express their comments concerning this petition should contact the Public Utility Commission of Texas, Office of Customer Protection, P.O. Box 13326, Austin, Texas 78711-3326, or call (512) 936-7120 or toll-free at (888) 782-8477. Hearing and speech-impaired individuals with text telephones (TTY) may call (512) 936-7136 or use Relay Texas (toll-free) 1-800-735-2989."

(B) Notices to revise fuel factors must also state the proposed fuel factors by type of voltage and the period for which the proposed fuel factors are expected to be in effect.

(C) Notices to revise fuel factors, to refund, or to surcharge must contain the statement that, "these changes will be subject to final review by the commission in the electric utility's next reconciliation," unless, in the case of refunds or surcharges, the change is a result of a reconciliation proceeding.

(D) Notices to reconcile fuel expenses must also state the period for which final reconciliation is sought.

(3) **Proof of notice may be demonstrated by appropriate affidavit.** In fuel proceedings initiated by a person other than an electric utility, the notice required in this subsection must be provided in accordance with a schedule ordered by the presiding officer.

(c) **Reports; confidentiality of information.** Matters related to submitting reports and confidential information will be handled as follows:

(1) The commission will monitor each electric utility's actual and projected fuel-related costs and revenues on a monthly basis. Each electric utility shall maintain and provide to the commission, in a format specified by the commission, monthly reports containing all information required to monitor monthly fuel-related costs and revenues, including generation mix, fuel consumption, fuel costs, purchased power quantities and costs, and system and off-system sales revenues.

(2) Contracts for the purchase of fuel, fuel storage, fuel transportation, fuel processing, or power are discoverable in fuel proceedings, subject to appropriate confidentiality agreements or protective orders.

(3) The electric utility shall prepare a confidentiality disclosure agreement to be included as part of the fuel reconciliation petition. The format for the agreement shall be the same as that contained in the commission approved rate filing package. In addition to the agreement itself, Attachment 1 of the agreement shall present a complete listing of the information required to be filed which the electric utility alleges is confidential. Upon request and execution of the confidentiality agreement, the electric utility shall provide any information which it alleges is confidential. If the electric utility fails to file a confidentiality agreement, the deadline for a commission final order in the case is tolled until a protective order is entered or a confidentiality agreement is filed. Use of the confidentiality disclosure agreement does not constitute a finding that any information is proprietary and/or confidential under law, or alter the burden of proof on that issue. The form of agreement contained in the commission approved rate filing package does not bind the examiner or the commission to accept the language of the agreement in the consideration of any subsequent protective order that may be entered.

(4) A party that cannot view a confidential document without receiving advantage as a competitor or bidder may hire outside counsel and consultants to view the document subject to a protective order.

§25.236. Recovery of Fuel Costs.

(a) **Eligible fuel expenses.** Eligible fuel expenses include expenses properly recorded in the Federal Energy Regulatory Commission Uniform System of Accounts, numbers 501, 502, 503, 509, 518, 536, 547, and 555, as modified in this subsection, as of April 1, 2013, and the items specified in paragraph (8) of this subsection. Any later amendments to the System of Accounts are not incorporated into this subsection. Subject to the commission finding special circumstances under paragraph (7) of this subsection, eligible fuel expenses are limited to:

(1) For any account, the electric utility may not recover, as part of eligible fuel expense, costs incurred after fuel is delivered to the generating plant site, for example, but not limited to, operation and maintenance expenses at generating plants, costs of maintaining and storing inventories of fuel at the generating plant site, unloading and fuel handling costs at the generating plant, and expenses associated with the disposal of fuel combustion residuals. Further, the electric utility may not recover maintenance expenses and taxes on rail cars owned or leased by the electric utility, regardless of whether the expenses and taxes are incurred or charged before or after the fuel is delivered to the generating plant site. The electric utility may not recover an equity return or profit for an affiliate of the electric utility, regardless of whether the affiliate incurs or charges the equity return or profit before or after the fuel is delivered to the generating plant site. In addition, all affiliate payments must satisfy the Public Utility Regulatory Act (PURA) §36.058.

(2) For Accounts 501 and 547, the only eligible fuel expenses are the delivered cost of fuel to the generating plant site excluding fuel brokerage fees. For Account 501, revenues associated with the disposal of fuel combustion residuals will also be excluded.

(3) For Account 502, the only eligible fuel expenses are environmental consumables that are: properly recorded in the Account as chemicals; required to comply with applicable state or federal emission reduction statutes, orders, and regulations; and whose use is directly proportional to the fuel consumed to generate electricity.

(4) For Account 509, the only eligible fuel expenses are allowances expensed concurrent with the monthly emissions of sulfur dioxide and nitrogen oxides.

(5) For Accounts 518 and 536, the only eligible fuel expenses are the expenses properly recorded in the Account excluding brokerage fees. For Account 503, the only eligible fuel expenses are the expenses properly recorded in the Account, excluding brokerage fees, return, non-fuel operation and maintenance expenses, depreciation costs and taxes.

(6) For Account 555, the electric utility may not recover demand or capacity costs.

(7) Upon demonstration that such treatment is justified by special circumstances, an electric utility may recover as eligible fuel expenses fuel or fuel related expenses otherwise excluded in paragraphs (1) - (6) of this subsection. In determining whether special circumstances exist, the commission shall consider, in addition to other factors developed in the record of the reconciliation proceeding, whether the fuel expense or transaction giving rise to the ineligible fuel expense resulted in, or is reasonably expected to result in, increased reliability of supply or lower fuel expenses than would otherwise be the case, and that such benefits received or expected to be received by ratepayers exceed the costs that ratepayers otherwise would have paid or otherwise would reasonably expect to pay.

(8) Eligible fuel expenses shall not be offset by revenues by affiliated companies for the purpose of equalizing or balancing the financial responsibility of differing levels of investment and operation costs associated with transmission assets. In addition to the expenses designated in paragraphs (1) - (7) of this subsection, unless otherwise specified by the commission, eligible fuel expenses shall be offset by:

(A) revenues from steam sales included in Accounts 504 and 456 to the extent expenses incurred to produce that steam are included in Account 503;

(B) revenues from off-system sales in their entirety, except as permitted in paragraph (9) of this subsection; and

(C) revenues from disposition of allowances properly recorded in Account 411.8.

(9) **Shared margins from off-system sales.** An electric utility may retain 10% of the margins from an off-system energy sales transaction if the following criteria are met:

(A) the electric utility participates in a transmission region governed by an independent system operator or a functionally equivalent independent organization;

(B) a generally-applicable tariff for firm and non-firm transmission service is offered in the transmission region in which the electric utility operates; and

(C) the transaction is not found to be to the detriment of its retail customers.

(b) **Reconciliation of fuel expenses.** Electric utilities shall file petitions for reconciliation on a periodic basis so that any petition for reconciliation shall contain a maximum of three years and a minimum of one year of reconcilable data and will be filed no later than six months after the end of the period to be reconciled.

(c) **Petitions to reconcile fuel expenses.** In addition to the commission prescribed reconciliation application, a fuel reconciliation petition filed by an electric utility must be accompanied by a summary and supporting testimony that includes the following information:

(1) a summary of significant, atypical events that occurred during the reconciliation period that affected the economic dispatch of the electric utility's generating units, including but not limited to transmission line constraints, fuel use or deliverability constraints, unit operational constraints, and system reliability constraints;

(2) a general description of typical constraints that limit the economic dispatch of the electric utility's generating units, including but not limited to transmission line constraints, fuel use or deliverability constraints, unit operational constraints, and system reliability constraints;

(3) the reasonableness and necessity of the electric utility's eligible fuel expenses and its mix of fuel used during the reconciliation period;

(4) a summary table that lists all the fuel cost elements which are covered in the electric utility's fuel cost recovery request, the dollars associated with each item, and where to find the item in the prefiled testimony;

(5) tables and graphs which show generation (MWh), capacity factor, fuel cost (cents per kWh and cents per MMBtu), variable cost and heat rate by plant and fuel type, on a monthly basis; and

(6) a summary and narrative of the next-day and intra-day surveys of the electricity markets and a comparison of those surveys to the electric utility's marginal generating costs.

(d) **Fuel reconciliation proceedings.** Burden of proof and scope of proceeding are as follows:

(1) In a proceeding to reconcile fuel factor revenues and expenses, an electric utility has the burden of showing that:

(A) its eligible fuel expenses during the reconciliation period were reasonable and necessary expenses incurred to provide reliable electric service to retail customers;

(B) if its eligible fuel expenses for the reconciliation period included an item or class of items supplied by an affiliate of the electric utility, the prices charged by the supplying affiliate to the electric utility were reasonable and necessary and no higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items; and

(C) it has properly accounted for the amount of fuel-related revenues collected pursuant to the fuel factor during the reconciliation period.

(2) The scope of a fuel reconciliation proceeding includes any issue related to determining the reasonableness of the electric utility's fuel expenses during the reconciliation period and whether the electric utility has over- or under-recovered its reasonable fuel expenses.

(e) **Refunds.** All fuel refunds and surcharges shall be made using the following methods.

(1) Interest shall be calculated on the cumulative monthly ending under- or over-recovery balance at the rate established annually by the commission for overbilling and underbilling in §25.28 (c) and (d) of this title (relating to Bill Payment and Adjustments). Interest shall be calculated based on principles set out in subparagraphs (A) - (E) of this paragraph.

(A) Interest shall be compounded annually by using an effective monthly interest factor.

(B) The effective monthly interest factor shall be determined by using the algebraic calculation x = (1 + i) (1/12) - 1; where i = commission-approved annual interest rate, and x = effective monthly interest factor.

(C) Interest shall accrue monthly. The monthly interest amount shall be calculated by applying the effective monthly interest factor to the previous month's ending cumulative under/over recovery fuel and interest balance.

(D) The monthly interest amount shall be added to the cumulative principal and interest under/over recovery balance.

(E) Interest shall be calculated through the end of the month of the refund or surcharge.

(2) Rate class as used in this subparagraph shall mean all customers taking service under the same tariffed rate schedule, or a group of seasonal agricultural customers as identified by the electric utility.

(3) Interclass allocations of refunds and surcharges, including associated interest, shall be developed on a month-by-month basis and shall be based on the historical kilowatt-hour usage of each rate class for each month during the period in which the cumulative under- or over-recovery occurred, adjusted for line losses using the same commission-approved loss factors that were used in the electric utility's applicable fixed or interim fuel factor.

(4) Intraclass allocations of refunds and surcharges shall depend on the voltage level at which the customer receives service from the electric utility. Retail customers who receive service at transmission voltage levels, all wholesale customers, and any groups of seasonal agricultural customers as identified by the electric utility shall be given refunds or assessed surcharges based on their individual actual historical usage recorded during each month of the period in which the cumulative under- or over-recovery occurred, adjusted for line losses if necessary. All other customers shall be given refunds or assessed surcharges based on the historical kilowatt-hour usage of their rate class.

(5) Unless otherwise ordered by the commission, all refunds shall be made through a one-time bill credit and all surcharges shall be made on a monthly basis over a period not to exceed 12 months through a bill charge. However, refunds may be made by check to municipally-owned electric utility systems if so requested. Retail customers who receive service at transmission voltage levels, all wholesale customers, and any groups of seasonal agricultural customers as identified by the electric utility shall be given a one-time credit or assessed a surcharge made on a monthly basis over a period not to exceed 12 months through a bill charge. All other customers shall be given a credit or assessed a surcharge based on a factor which will be applied to their kilowatt-hour usage over the refund or surcharge period. This factor will be determined by dividing the amount of refund or surcharge allocated to each rate class by forecasted kilowatt-hour usage for the class during the period in which the refund or surcharge will be made.

(6) A petition to surcharge or refund a fuel under- or over-recovery balance not associated with a proceeding under subsection (d) of this section shall be processed in accordance with the filing

schedules in §25.237(d) of this title (relating to Fuel factors) and the deadlines in §25.237(e) of this title.

(f) **Procedural schedule.** Upon the filing of a petition to reconcile fuel expenses in a separate proceeding, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding within one year after a materially complete petition was filed. However, if the deadlines result in a number of electric utilities filing cases within 45 days of each other, the presiding officers shall schedule the cases in a manner to allow the commission to accommodate the workload of the cases irrespective of whether such procedural schedule enables the commission to issue a final order in each of the cases within one year after a materially complete petition is filed.

§25.237. Fuel Factors.

(a) **Use and calculation of fuel factors.** An electric utility's fuel costs will be recovered from the electric utility's customers by the use of a fuel factor that will be charged for each kilowatt-hour (kWh) consumed by the customer.

(1) An electric utility may determine its fuel factor in dollars per kilowatt-hour pursuant to either subparagraph (A) or (B) of this paragraph. Fuel factors must account for system losses and for the difference in line losses corresponding to the voltage at which the electric service is provided. An electric utility may have different fuel factors for different times of the year to account for seasonal variations. A different method of calculation may be allowed upon a showing of good cause by the electric utility.

(A) Fuel factors may be determined by dividing the electric utility’s projected net eligible fuel expenses, as defined in §25.236(a) of this title (relating to Recovery of Fuel Costs), by the corresponding projected kilowatt-hour sales for the period in which the fuel factors are expected to be in effect.

(B) Fuel factors may be determined using a commission-approved, utility-specific fuel factor formula. Fuel factor formulas may be approved or revised only in a general rate change proceeding or a proceeding to consider an application to establish a fuel factor formula with notice and an opportunity for a hearing.

(2) An electric utility may initiate a change to its fuel factor as follows:

(A) Pursuant to subsection (a)(1)(A) of this section, an electric utility may petition to adjust its fuel factor as often as once every four months according to the schedule set out in subsection (d) of this section.

(B) Pursuant to subsection (a)(1)(B) of this section, an electric utility may petition to adjust its fuel factor in accordance with its approved fuel factor formula no sooner than four months after the filing of its most recent fuel factor adjustment petition.

(C)Notwithstanding subsection (a)(2)(A) of this section, an electric utility may petition to change its fuel factor at times other than provided in the schedule if an emergency exists as described in subsection (f) of this section.

(D) An electric utility's fuel factor may be changed in any general rate proceeding.

(3) Fuel factors are temporary rates, and the electric utility's collection of revenues by fuel factors is subject to the following adjustments:

(A) The reasonableness of the fuel costs that an electric utility has incurred will be periodically reviewed in a reconciliation proceeding, as described in §25.236 of this title, and any disallowed costs resulting from a reconciliation proceeding will be reflected in the calculation of the utility’s recoverable fuel and over/(under) collections.

(B) To the extent that there are variations between the fuel costs incurred and the revenues collected, it may be necessary or convenient to refund overcollections or surcharge undercollections. Refunds or surcharges may be made without changing an electric utility's fuel factor. Nothwithstanding §25.236(e)(6) of this title, an electric utility may petition for a surcharge any time it has materially undercollected its fuel costs and projects that it will continue to be in a state of material undercollection. Notwithstanding §25.236(e)(6) of this title, an electric utility shall petition to make a refund any time it has materially overcollected its fuel costs and projects that it will continue to be in a state of material overcollection. "Materially" or "material," as used in this section, shall mean that the cumulative amount of over- or under-recovery, including interest, is greater than or equal to 4.0% of the annual actual fuel cost figures on a rolling 12-month basis, as reflected in the utility’s monthly fuel cost reports as filed by the utility with the commission.

(b) **Petitions to revise fuel factors.**

(1) An electric utility using the fuel factor methodology set forth under subsection (a)(1)(A) of this section may file a petition requesting revised fuel factors pursuant to subsection (a)(2)(A) of this section during the first five business days of the months specified in subsection (d) of this section. A copy of the complete petition package shall be served on each party in the utility's most recent fuel reconciliation and on the Office of Public Utility Counsel. Service shall be accomplished by email if possible. Each complete filing package shall include the commission-prescribed fuel factor application, a tariff sheet reflecting the proposed fuel factors and supporting testimony that includes the following information:

(A) For each month of the period in which the fuel-factor has been in effect and has not been reconciled up to the most recent month for which information is available,

(i) the revenues collected pursuant to fuel factors by customer class;

(ii) any other items that to the knowledge of the electric utility have affected fuel factor revenues and eligible fuel expenses; and

(iii) the difference, by customer class, between the revenues collected pursuant to fuel factors and the eligible fuel expenses incurred.

(B) For each month of the period for which the revised fuel factors are expected to be in effect, provide system energy input and sales, accompanied by the calculations underlying any differentiation of fuel factors to account for differences in line losses corresponding to the voltage at which the electric service is provided.

(2) An electric utility using the fuel factor formula methodology set forth under subsection (a)(1)(B) of this section may file a petition requesting revised fuel factors pursuant to subsection (a)(2)(B) of this section at least 15 days prior to the first billing cycle in the billing month in which the proposed fuel factors are requested to become effective. A copy of the complete petition package shall be served on each party in the utility's most recent fuel reconciliation and on the Office of Public Utility Counsel. Service shall be accomplished by email if possible. Each complete filing package shall include:

(A) a tariff sheet reflecting the proposed fuel factors;

(B) workpapers supporting the calculation of the revised fuel factors;

(C)calculations underlying any differentiation of fuel factors to account for differences in line losses corresponding to the voltage at which the electric service is provided; and

(D) any computer generated documents must be provided in their native electronic format with all cells and internal formulas disclosed.

(c) **Fuel factor revision proceeding.** Burden of proof and scope of proceeding are as follows:

(1) In a proceeding to revise fuel factors pursuant to subsection (a)(1)(A) of this section, an electric utility has the burden of proving that:

(A) the expenses proposed to be recovered through the fuel factors are reasonable estimates of the electric utility's eligible fuel expenses during the period that the fuel factors are expected to be in effect;

(B) the electric utility's estimated monthly kilowatt-hour system sales and off-system sales are reasonable estimates for the period that the fuel factors are expected to be in effect; and

(C)the proposed fuel factors are reasonably differentiated to account for line losses corresponding to the voltage at which the electric service is provided.

(2) The scope of a fuel factor revision proceeding under subsection (a)(1)(B) of this section is limited to the issue of whether the petitioning electric utility has appropriately calculated its proposed fuel factors. In a proceeding to revise fuel factors pursuant to subsection (a)(1)(B) of this section, an electric utility has the burden of proving that:

(A) the electric utility has calculated its proposed fuel factors in compliance with the commission-approved fuel factor formula; and

(B) the proposed fuel factors utilize a commission-approved adjustment to account for line losses corresponding to the voltage at which the electric service is provided.

(d) **Schedule for filing petitions to revise fuel factors**. A petition to revise fuel factors or to initiate or revise a fuel factor formula may be filed with any general rate proceeding.

(1) Otherwise, except as provided by subsection (f) of this section which addresses emergencies, petitions by an electric utility to revise fuel factors pursuant to subsection (a)(1)(A) of this section may only be filed in accordance with the following schedule:

(A) February, June and October : El Paso Electric Company;

(B) March, July and November : Entergy Texas, Inc.;

(C)April, August and December : Southwestern Public Service Company;

(D) May, September and January : Southwestern Electric Power Company; and

(E)March, July and November : any other electric utility not named in this subsection that uses one or more fuel factors.

(2) Petitions by an electric utility to revise fuel factors pursuant to subsection (a)(1)(B) of this section may be filed in any month except December.

(e) **Procedural schedules.**

(1) Upon the filing of a petition to revise fuel factors pursuant to subsection (a)(1)(A) of this section, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding as follows:

(A) within 60 days after the petition was filed, if no hearing is requested within 30 days of the petition; and

(B) within 90 days after the petition was filed, if a hearing is requested within 30 days of the petition. If a hearing is requested, the hearing will be held no earlier than the first business day after the 45th day after the application was filed.

(2) Upon the filing of a petition to revise fuel factors pursuant to subsection (a)(1)(B) of this section, the presiding officer shall set a procedural schedule as follows:

(A) the presiding officer shall issue an order approving the proposed fuel factors on an interim basis no later than 12 days after the date the petition was filed, if no objection to interim approval is filed within 10 days after the date the petition was filed;

(B) if no hearing is requested within 30 days after the petition was filed, the presiding officer shall, after submission of proof of notice by the electric utility, issue an order approving the fuel factors without hearing or action by the commission; and

(C)if a hearing is requested within 30 days after the petition was filed, the hearing will be held no earlier than the first business day after the 45th day after the petition was filed and a final order will be issued within 90 days after the petition was filed, subject to submission of proof of notice by the electric utility.

(f) **Emergency revisions to the fuel factor.** If fuel curtailments, equipment failure, strikes, embargoes, sanctions, or other reasonably unforeseeable circumstances have caused a material under-recovery of eligible fuel costs, the electric utility may file a petition with the commission requesting an emergency interim fuel factor. Such emergency requests shall state the nature of the emergency, the magnitude of change in fuel costs resulting from the emergency circumstances, and other information required to support the emergency interim fuel factor. The commission shall issue an interim order within 30 days after such petition is filed to establish an interim emergency fuel factor. If within 120 days after implementation, the emergency interim factor is found by the commission to have been excessive, the electric utility shall refund all excessive collections with interest calculated on the cumulative monthly ending under- or overrecovery balance in the manner and at the rate established by the commission for overbilling and underbilling in §25.28(c) and (d) of this title (relating to Bill Payment and Adjustments Billing). If, after full investigation, the commission determines that no emergency condition existed, a penalty of up to 10% of such over-collections may also be imposed on investor-owned electric utilities.

§25.238. Purchased Power Capacity Cost Recovery Factor (PCRF).

(a) **Application.** This section applies to an electric utility that sells electricity.

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

(1) **Class billing determinants** -- Kilowatt-hours (kWh) for each class that is not billed using a demand charge, and kilowatts (kW) for each class that is billed using a demand charge.

(2) **Cost year** -- the most recent historical 12-month period for which data are available at the time a utility prepares an application to establish, adjust, or terminate a PCRF.

(3) **Net production capacity invested capital --** Production capacity invested capital costs recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 310 - 317, 320 - 326, 330 - 337, and 340 - 347, less accumulated depreciation and adjusted for any changes in production capacity-related accumulated deferred federal income taxes and excluding any impact associated with Financial Accounting Standards Board Interpretation No. 48.

(c) **Establishment, adjustment, and termination of a PCRF.**

(1) A utility may apply for establishment of a PCRF rider only if all of the following conditions are met:

(A) the utility's most recent comprehensive base-rate proceeding established sufficient information to allow for the determination of values for the parameters in subsection (h) of this section;

(B) no more than two years have passed since the final order in the utility's most recent comprehensive base-rate proceeding;

(C) the utility has not had a PCRF in effect within the last year; and

(D) no PCRF has been in effect for the utility since the final order in the utility's most recent comprehensive base-rate proceeding.

(2) The application in which the utility applies for the establishment, adjustment, or termination of a PCRF rider shall be limited to issues related to the establishment, adjustment, or termination of the PCRF rider.

(3) The PCRF shall not include:

(A) the cost of capacity purchased directly or indirectly from an affiliate, as defined in §25.5(3) of this title (relating to Definitions), of the utility, including, without limitation, whether such capacity is acquired through one or more intermediaries or pursuant to a FERC approved agreement or tariff of a Regional Transmission Organization or Independent System Operator, unless such affiliate-related purchases have been previously approved by the commission in a proceeding under subsection (d) of this section;

(B) the cost of capacity owned by the utility;

(C) any costs recoverable by the utility under §25.236 of this title (relating to Recovery of Fuel Costs), including purchases of firm energy;

(D) any costs for purchases made through day-ahead or real-time markets of a Regional Transmission Organization or Independent System Operator.

(4) Upon the establishment of a utility's PCRF, the utility shall annually file an application for an adjustment of the PCRF. The cost year used in an annual PCRF adjustment shall be the 12-month period that immediately follows the cost year used to set the existing PCRF. In addition, the utility shall file the application to adjust the PCRF promptly after the relevant cost-year data become available. The commission may establish a schedule for the filing of such applications.

(5) A utility may terminate its PCRF as part of any annual PCRF adjustment proceeding. The final order including the termination of a PCRF shall specify the date by which the utility shall be required to file an application for the final reconciliation of the costs and revenues associated with the terminated PCRF.

(6) Commission staff may petition at any time to terminate a utility's PCRF.

(7) A utility's request to establish, adjust, terminate, or reconcile a PCRF shall include the utility's direct testimony supporting the request.

(d) **Pre-approval of purchased power agreements.**

(1) The commission may pre-approve a utility's executed agreement for the purchase of power capacity from an affiliate if it finds that the agreement is reasonable, and the utility may thereafter seek to include the capacity costs incurred under such a commission-approved agreement in its PCRF rider.

(2) Though not required for inclusion in a PCRF rider, a utility may seek commission review of the reasonableness of a utility's executed agreement for the purchase of power capacity from a non-affiliate, and the utility may seek to include the capacity costs incurred under such a commission-approved agreement in its PCRF rider.

(3) Agreements under paragraphs (1) and (2) of this subsection may include an agreement for the purchase of capacity to be delivered in the future that relies on the construction of a generating unit or units.

(4) An application in which the utility applies for pre-approval of purchased power capacity agreements under this subsection shall be limited to issues related to the pre-approval of such agreements.

(5) A utility may apply for pre-approval of purchased power agreements under this subsection no more than once per year, and no more than three times between comprehensive base-rate proceedings.

(e) **Notice of PCRF proceeding.**

(1) Within one commission working day of filing an application limited to establishing, adjusting, or terminating a PCRF, a utility shall provide notice of the application in accordance with the following:

(A) **Method of notice.**

(i) The utility shall serve notice of the application on the parties to the utility's last PCRF reconciliation proceeding or, if there has been no PCRF reconciliation proceeding, on the parties to the utility's last comprehensive base-rate proceeding.

(ii) The utility shall issue a news release and post the news release on its website.

(B) **Content of notice.** Notice provided pursuant to paragraph (1) of this subsection shall include the following:

(i) The date the application was filed;

(ii) A description of the application, including the relief requested;

(iii) The date of the intervention and hearing request deadline. The date of the intervention and hearing request deadline shall be 30 days after the application was filed, except that if the date would fall on a day that is not a commission working day, the intervention and hearing request deadline shall be the first commission working day after the 30^{th} day after the application was filed;

(iv) To the extent applicable, the existing PCRF and the proposed PCRF by rate class, and the percentage difference between the two;

(v) For an application seeking to establish or adjust a PCRF, the following statement: "The PCRF is subject to final review in the next PCRF reconciliation.";

(vi) The statement, "Persons with questions or who want more information on this application may contact (utility name) at (utility address) or call (utility toll-free telephone number) during normal business hours. A complete copy of this application is available for inspection at the address listed above"; and

(vii) The statement, "Persons who wish to intervene in the proceeding for this application, or who wish to provide their comments concerning this application, should contact the Public Utility Commission of Texas, Customer Protection Division, P.O. Box 13326, Austin, Texas 78711-3326, or call (512) 936-7120 or toll-free at (888) 782-8477. Hearing and speech-impaired individuals with text telephones (TTY) may call (512) 936-7136 or use Relay Texas (toll-free) 1-800-735-2989."

(C) **Proof of notice.** Within five commission working days from the filing of the application limited to establishing or adjusting a PCRF, the utility shall file proof in the form of an affidavit that it complied with this paragraph.

(2) If a utility applies to reconcile a PCRF in a base-rate proceeding, the appropriate method and proof of notice set forth in §22.51 of this title (relating to Notice for Public Utility Regulatory Act, Chapter 36, Subchapters C-E; Chapter 51, §51.009; and Chapter 53, Subchapters C-E Proceedings) shall apply. The notice shall include a description of the requested change to the PCRF.

(3) If a utility applies to reconcile a PCRF outside of a base-rate proceeding, the method of notice set forth in §25.235(b)(1)(B) of this title (relating to Fuel Costs-General) shall apply. The proof of notice set forth in §25.235(b)(3) of this title shall apply. The notice shall include a description of the requested reconciliation of the PCRF.

(f) **Procedural schedule.** Upon the filing of an application limited to the annual adjustment of a PCRF pursuant to this section, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding as follows, except where good cause supports a different procedural schedule:

(1) within 60 days after a sufficient application was filed, if no hearing is requested within 30 days of the filing of the application; or

(2) within 120 days after a sufficient application was filed, if a hearing is requested within 30 days of the filing of the application. If a hearing is requested, the hearing will be held no earlier than the first working day after the 45th day after a sufficient application was filed.

(g) **Exclusion from fuel factor.** Costs that are recovered through a PCRF shall be excluded in calculating the utility's fixed fuel factor as defined in §25.237 of this title (relating to Fuel Factors).

(h) **PCRF formula.**

(1) The PCRF for each rate class shall be calculated using the following formula:

$$\mathbf{PCRF = (\{(((PPC_{CY} + AAC_{CY} + APC_{M}) * TRAF_{CY}) - OSM_{CY}) * CAF_{CY}\} - \{(PPC_{RC\text{-}CLASS} + APC_{RC\text{-}CLASS} - OSM_{RC\text{-}CLASS}) * LGR\} - \{((PCIC_{RC\text{-}CLASS} * ROR_{AT}) + PCDEP_{RC\text{-}CLASS} + PCFIT_{RC\text{-}CLASS} + PCOT_{RC\text{-}CLASS}) * LGI\} + CTU) / CBD_{E}}$$

Where:

PPC_{CY} = Cost-year purchased power capacity costs from entities that are not affiliates, in accordance with subsection (c)(3) of this section.
AAC_{CY} = Cost-year purchased power capacity costs from entities that are affiliates and which costs are incurred from agreements that have been pre-approved by the commission in a proceeding under subsection (d) of this section as of the date of the filing of the instant PCRF application.
APC_{M} = The lesser of:

- purchased power capacity costs from affiliates used to set base rates in the utility's last comprehensive base-rate proceeding, or
- cost-year purchased power capacity costs from affiliates less AAC_{CY}.

OSM_{CY} = Cost-year margins from wholesale power capacity sales transactions.
$TRAF_{CY}$ = Cost-year value of the Texas retail jurisdiction production demand allocation factor, using the same type of production demand allocation factor used to set rates in the utility's last comprehensive base-rate proceeding.
CAF_{CY} = Cost-year value of the corresponding rate class production demand allocation factor, using the same type of production demand allocation factor used to set rates in the utility's last comprehensive base-rate proceeding.
$PPC_{RC\text{-}CLASS}$ = Purchased power capacity costs from entities that are not affiliates, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.
$APC_{RC\text{-}CLASS}$ = Purchased power capacity costs from affiliates allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.
$OSM_{RC\text{-}CLASS}$ = Margins from wholesale power capacity sales allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.
LGR = The greater of (CBD_{CY} / CBD_{RC}) or 1.
CBD_{CY} = Cost-year rate class billing determinants.
CBD_{RC} = Rate class billing determinants used to calculate base rates from the utility's last comprehensive base-rate proceeding.
$PCIC_{RC\text{-}CLASS}$ = Net production capacity invested capital allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.
ROR_{AT} = The after-tax rate of return used to set base rates from the utility's last comprehensive base-rate proceeding.
$PCDEP_{RC\text{-}CLASS}$ = Depreciation expense, as related to gross production capacity, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.
$PCFIT_{RC\text{-}CLASS}$ = Federal income tax, as related to net production capacity invested capital, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.
$PCOT_{RC\text{-}CLASS}$ = Other taxes, as related to net production capacity invested capital, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding, and not including municipal franchise fees.
LGI = The greater of ((CBD_{CY} – CBD_{RC}) / CBD_{RC}) or 0.
CTU = The rate class under/(over)-recovery, including interest, as calculated in subsection (i) of this section.
CBD_{E} = Estimated PCRF rate year class billing determinants.

(2) Where the cost year used in setting a PCRF includes a change in base rates due to a comprehensive base-rate proceeding, parameters in the PCRF formula that refer to values from the utility's last comprehensive base-rate proceeding shall be calculated by prorating the values from the relevant base rate-proceedings across the cost-year.

(i) **True-up**. After establishment of an initial PCRF, a subsequent PCRF cost year is expected to contain portions of two different PCRF rate years. Therefore, for purposes of calculating class over- or under-recoveries for use in a proceeding to adjust the PCRF, previous PCRF revenue requirements from PCRF rate years in effect during the cost year shall be prorated across the cost year. For each rate class, the difference between the prorated cost-year PCRF revenue requirement that previous PCRFs were set to recover from that class and the actual cost-year PCRF revenues recovered from that class, with interest on the balance calculated at the rate established annually by the commission pursuant to §25.28(c) and (d) of this title (relating to Bill Payment and Adjustments), shall be credited or charged to that class when calculating the adjusted PCRF. In the event that a PCRF rider is terminated, any over- or under-recovery amounts, with interest applied, shall be included in a separate rider.

(j) **Reconciliation of PCRF expenses.**

(1) The reasonableness and necessity of expenses recovered through the PCRF shall be reviewed, and such costs and corresponding PCRF revenues shall be reconciled, as part of any proceeding initiated under §25.236(b) of this title. Upon motion and showing of good cause, a PCRF reconciliation proceeding may be severed from or consolidated with other proceedings.

(2) In a proceeding in which PCRF costs are being reconciled, the electric utility has the burden of showing that:

(A) its expenses recovered through the PCRF during the reconciliation period were reasonable and necessary expenses incurred to provide reliable electric service to retail customers; and

(B) it has properly accounted for the amount of purchased power capacity-related revenues collected pursuant to the PCRF and corresponding to costs reviewed during the reconciliation period.

(3) Any refunds or surcharges resulting from a PCRF reconciliation, with interest applied, shall, in the annual PCRF proceeding immediately subsequent to the filing of the final order in the reconciliation proceeding, be incorporated into the true-up balances described in subsection (i) of this section. In the event that no PCRF rider is in effect subsequent to a PCRF reconciliation, such refunds or surcharges, with interest applied, shall be included in a separate rider.

(k) **Transition Issues.**

For a utility subject to a commission order to transition to retail competition as of the effective date of this section, the utility's existing power cost recovery factor in its tariff approved under the prior rule shall continue to be effective until the effective date of new unbundled retail delivery tariffs for the utility, at which time the power cost recovery factor shall be terminated. Any over- or under-recovery amounts, with interest applied, shall be included in a separate rider to the utility's retail delivery tariffs to be established in the proceeding that approves such tariffs and shall be credited or charged to customers as appropriate. The utility shall file monthly reports with the commission showing all such amounts until no remaining amounts remain to be credited or charged, at which time the utility shall file a final report with the commission.

§25.239. Transmission Cost Recovery Factor for Certain Electric Utilities.

(a) **Application.** The provisions of this section apply to an electric utility that operates solely outside of the Electric Reliability Council of Texas in areas of Texas included in the Southwest Power Pool or the Western Electricity Coordinating Council and that owns or operates transmission facilities.

(b) **Definitions.**

(1) **Approved transmission charges (ATC) —** Wholesale transmission charges approved by a federal regulatory authority that are not being recovered through the electric utility's other retail or wholesale rates and that are appropriately allocated to Texas retail customers. The charges may relate to the use of transmission facilities owned and operated by another transmission service provider or regional transmission organization, including transmission-related administrative fees but not including dispatch fees, congestion charges, costs incurred to hedge congestion charges, or ancillary service charges.

(2) **Transmission invested costs (TIC) —** The net change in the electric utility's transmission investment costs including additions, upgrades, and retirements as booked in FERC accounts 350-359, and accumulated depreciation.

(c) **Recovery authorized.** The commission, after notice and hearing, may allow an electric utility to recover its reasonable and necessary costs for transmission infrastructure improvement and changes in wholesale transmission charges to the electric utility under a tariff approved by a federal regulatory authority to the extent that the costs or charges have not otherwise been recovered and are incurred after December 31, 2005. Any such recovery shall be made through the use of a transmission cost recovery factor (TCRF) approved by an order of the commission. The TCRF shall be calculated pursuant to subsection (d) of this section. If a utility has not had a base rate case with a final order issued after December 2005, the utility shall not be eligible for recovery under this provision without first obtaining a final order in a base rate case.

(d) **Transmission cost recovery factor (TCRF).** The TCRF shall be determined by the following formula:

$$\mathbf{TCRF} = \frac{\boldsymbol{RR * ClassALLOC}}{\boldsymbol{BD}}$$

Where:	TCRF = transmission cost recovery factor in dollars per unit, for billing each customer class.
	RR = transmission cost recovery factor revenue requirement, calculated pursuant to subsection (e) of this section.
	ClassALLOC = the customer class allocation factor used to allocate the transmission revenue requirement in the utility's most recent base rate case.
	BD = each customer class's annual billing determinant (kilowatt-hour, kilowatt, or kilovolt-ampere) for the previous calendar year.

(e) **Transmission cost recovery factor revenue requirement (RR).** For an electric utility subject to this section, the transmission cost recovery factor revenue requirement (RR) shall be calculated by using the following formula:

RR = [revreqt + ATC]*ALLOC	
Where:	Revreqt = the sum of the return on TIC, net of accumulated depreciation and associated accumulated deferred income taxes, plus investment-related expenses such as income taxes, other associated taxes, depreciation, and transmission–related miscellaneous revenue credits, but not including operation and maintenance expenses or administrative expenses. The return on TIC shall be calculated by multiplying the TIC by the utility's weighted-average cost of capital (WACC) as established for the utility in a final commission order in a base rate case, provided that the order was filed within three years prior to the initiation of the TCRF docket. Otherwise, a proxy WACC shall be used, with a cost of equity of 10%; and the capital structure and cost of debt as reported in the utility's most recent Earnings Monitoring Report filed pursuant to §25.73 of this title (relating to Financial and Operating Reports), adjusted for known and measurable changes.
	Transmission Invested Costs (TIC) is defined in subsection (b)(2) of this section.
	Approved Transmission Charges (ATC) is defined in subsection (b)(1) of this section.
	ALLOC = the utility's Texas retail allocation of transmission revenue requirements, as established in the utility's most recent base rate case.

(f) **Setting and amending the TCRF.** An electric utility that is subject to this section may file an application to set or amend a TCRF. The commission staff may also file an application to amend a TCRF. An electric utility may not apply to amend its TCRF more frequently than once each calendar year, but a TCRF shall be reviewed or amended at least once every three years. Upon completion of a base rate case for a utility, the TCRF shall be set to zero. In a docket in which the TCRF is reviewed or amended, the commission may order the refund of any previous over-recovery, but the commission shall not order the surcharge of any under-recovery. An over-recovery shall be considered to have occurred if the revenues from the TCRF were greater than the costs that the TCRF was intended to recover.

(g) **TCRF forms.** The commission may develop forms for TCRF applications and for monitoring the revenues from a TCRF. If the commission develops and approves such forms, an electric utility shall use the forms as required by the instructions accompanying the form.

§25.240. Contribution Disclosure Statements in Appeals of Municipal Utility Rates.

(a) **Pursuant to Chapter 33, Subchapter D.** Each party to an appeal proceeding under the Public Utility Regulatory Act (PURA), Chapter 33, Subchapter D must file a statement with the commission disclosing all expenditures made by that party and all contributions made to that party, whether the expenditures or contributions are financial or in-kind, related to preparation of and filing of a petition for appeal, the preparation of expert testimony, and legal representation in the proceeding. The municipality whose rates are the subject of the appeal, the Office of Regulatory Affairs, and the Office of Public Utility Counsel are not required to file a statement. The statement must list with particularity the name and address of each contributor and provide a description of each contribution. The statement will be available to the public. The statement must be filed within 30 days after a final appealable order is entered by the commission or the petition of appeal is withdrawn.

(b) **Pursuant to PURA §33.123.** Any party that brings an appeal under PURA §33.123 (appellant) must file within 30 days after filing the appeal with the commission and within each 30 days thereafter, a statement that discloses with particularity each and every contribution, whether financial or in-kind, made to the appellant in support of the appeal. This obligation will continue until a statement is filed that includes all contributions made up until the commission has entered a final appealable order. The statement will list the name and address of each contributor and provide a description of each contribution.

(c) **Hearings on statements.** Upon motion by any party or upon the commission's own motion, the commission may conduct a hearing on the statements to make such determinations as may be necessary under PURA, Chapter 33, Subchapter D or §33.123.

Subchapter J. COSTS, RATES, AND TARIFFS.

DIVISION 1. RETAIL RATES.

§25.241. Form and Filing of Tariffs.

(a) **Application**. This section applies to all electric utilities.

(b) **Effective tariff**. No utility shall directly or indirectly offer any service, collect any rate or charge, give any compensation or discount to a customer, or impose any classification, practice, or regulation different from that which is prescribed in its effective tariff filed with the commission. The tariff may include mathematical formulas that express the pricing terms for service. Every contract for electric service between an electric utility and a customer shall be deemed to be part of the effective tariff, and shall be filed with the commission upon request.

(c) **Requirements as to size, form, identification and filing of tariffs.**

(1) Every public utility shall file with the commission filing clerk five copies of its tariff containing schedules of all its rates, tolls, charges, rules, and regulations pertaining to all of its utility service. It shall also file five copies of each subsequent revision. Each revision shall be accompanied by a cover page which contains a list of pages being revised, a statement describing each change, its effect if it is a change in an existing rate, and a statement as to impact on rates of the change by customer class, if any. If a proposed tariff revision constitutes an increase in existing rates of a particular customer class or classes, then the commission may require that notice be given.

(2) All tariffs shall be in loose-leaf form of size 8 1/2 inches by 11 inches and shall be plainly printed or reproduced on paper of good quality. The front page of the tariff shall contain the name of the utility and location of its principal office and the type of service rendered (telephone, electric, etc.).

(3) Each rate schedule must clearly state the territory, city, county, or exchange wherein said schedule is applicable.

(4) Tariff sheets are to be numbered consecutively per schedule. Each sheet shall show an effective date, a revision number, section number, sheet number, page number, name of the utility, the name of the tariff, and title of the section in a consistent manner. Sheets issued under new numbers are to be designated as original sheets. Sheets being revised should show the number of the revision, and the sheet numbers shall be the same.

(d) **Composition of tariffs**. The tariff shall contain sections and subsections setting forth:

(1) a table of contents;

(2) a list of the cities and counties in which service is provided;

(3) a brief description of the utility's operations;

(4) the rate schedules; and

(5) the service regulations, including the service agreement forms.

(e) **Tariff filings in response to commission orders.** Tariff filings made in response to an order issued by the commission shall include a transmittal letter stating that the tariffs attached are in compliance with the order, giving the docket number, date of the order, a list of tariff sheets filed, and any other necessary information. The tariff sheets shall comply with all other rules in this chapter and shall include only changes ordered. The effective date and/or wording of said tariffs shall comply with the provisions of the order.

(f) **Symbols for changes.** Each proposed tariff sheet shall contain notations in the right-hand margin indicating each change made on these sheets. Notations to be used are: (C) to denote a change in regulations; (D) to denote discontinued rates or regulations; (E) to denote the correction of an error made during a revision (the revision which resulted in the error must be one connected to some material contained in the tariff prior to the revision); (I) to denote a rate increase; (N) to denote a new rate or regulation; (R) to denote a rate reduction; and (T) to denote a change in text, but no change in rate or regulation. In addition to symbols for changes, each changed provision in the tariff shall contain a vertical line in the right-hand margin of the page, which clearly shows the exact number of lines being changed.

(g) **Availability of tariffs.** Each utility shall make available to the public at each of its business offices or designated sales offices within Texas all of its tariffs currently on file with the commission, and its employees shall lend assistance to persons seeking information on its tariffs and afford inquirers an opportunity to examine any tariff upon request. The utility also shall provide copies of any portion of its tariffs at a reasonable cost.

(h) **Rejection.** If a tariff filed with the commission is found not to be in compliance with these sections, commission Staff shall file a brief explanation of the reasons for rejection.

(i) **Effective date of tariff change.** No jurisdictional tariff change may take effect prior to 35 days after filing without commission approval. The requested date will be assumed to be 35 days after filing unless a different date is requested in the application. The commission may suspend the effective date of the tariff change for 120 days after the requested effective date and may extend that suspension another 30 days if required for final determination. In the case of an actual hearing on the merits of a case that exceeds 15 days, the suspension date is extended two days for each one day of actual hearing in excess of 15 actual hearing days.

(j) **Compliance**. Electric utilities that file new tariffs or tariff revisions shall comply with the 1998 amendments to this section with respect to the new or revised tariffs.

§25.242. Arrangements Between Qualifying Facilities and Electric Utilities.

(a) **Purpose.** The purpose of this section is to regulate the arrangements between qualifying facilities, retail electric providers with the price to beat obligation (PTB REPs), and electric utilities as required by federal and state law in a manner consistent with the development of a competitive wholesale power market.

(b) **Application.** This section applies to all PTB REPs and to all electric utilities, including transmission and distribution utilities. The provisions of this section concerning purchase or sale of electricity between an electric utility and a qualifying facility do not apply to a transmission and distribution utility. This section does not apply to municipal utilities, river authorities, or electric cooperatives.

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

(1) **Avoided costs** -- The incremental costs to a PTB REP, or electric utility of electric energy, which, but for the purchase from the qualifying facility or qualifying facilities, such PTB REP or electric utility would generate itself or purchase from another source.

(2) **Back-up power** -- Electric energy or capacity supplied to replace energy or capacity ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the qualifying facility.

(3) **Cost of decremental energy** -- The cost savings to a utility associated with the utility's ability to back-down some of its units or to avoid firing units, or to avoid purchases of power from another source because of purchases of power from qualifying facilities.

(4) **Electric utility** -- For purposes of this section, an integrated investor-owned utility that has not unbundled in accordance with Public Utility Regulatory Act §39.051.

(5) **Firm power** -- From a qualifying facility, power or power-producing capacity that is available pursuant to a legally enforceable obligation for scheduled availability over a specified term.

(6) **Host utility** -- The utility with which the qualifying facility is directly interconnected.

(7) **Maintenance power** -- Electric energy or capacity supplied during scheduled outages of the qualifying facility.

(8) **Market price** -- The market-clearing price of energy (MCPE) in the balancing energy market for the Electric Reliability Council of Texas (ERCOT) congestion zone in which the power is produced, minus any administrative costs, including an appropriate share of ERCOT-assessed penalties and fees typically applied to power generators.

(9) **Non-firm power from a qualifying facility** -- Power provided under an arrangement that does not guarantee scheduled availability, but instead provides for delivery as available.

(10) **Parallel operation** -- A mode of operation which enables a qualifying facility to export automatically any electric capacity which is not consumed by the qualifying facility or the user of the qualifying facility's output. Parallel operation results in three possible states of operation at any point in time:

(A) The qualifying facility is generating an amount of capacity that is less than the customer's load. The customer is therefore a net consumer.

(B) The qualifying facility is generating an amount of capacity that is more than the customer's load. The customer is therefore a net producer.

(C) The qualifying facility is generating an amount of capacity that is equal to the customer's load. The customer is therefore neither a net producer nor a net consumer.

(11) **Purchase** -- The purchase of electric energy or capacity or both from a qualifying facility by a PTB REP or electric utility.

(12) **Purchasing utility** -- The electric utility that is purchasing a qualifying facility's capacity and/or energy.

(13) **Quality of firmness of a qualifying facility's power** -- The degree to which the capacity offered by the qualifying facility is an equivalent quality substitute for firm purchased power or an electric utility's own generation. At a minimum the following factors should be considered in determining quality of firmness:
   - (A) reliability of generation and interconnection;
   - (B) forced outage rate;
   - (C) availability during peak periods;
   - (D) the terms of any contract or other legally enforceable obligation, including, but not limited to, the duration of the obligation, performance guarantees, termination notice requirements, and sanctions for noncompliance;
   - (E) maintenance scheduling;
   - (F) availability for system emergencies, including the ability to separate the qualifying facility's load from its generation;
   - (G) the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system;
   - (H) other dispatch characteristics;
   - (I) reliability of primary and secondary fuel supplies used by the qualifying facility; and
   - (J) impact on utility system stability.

(14) **Retail electric provider with the price to beat obligation (PTB REP) --** A REP that makes available a PTB pursuant to PURA §39.202.

(15) **Sale** -- The sale of electric energy or capacity or both supplied to a qualifying facility.

(16) **Supplementary power** -- Electric energy or capacity regularly used by a qualifying facility in addition to that which the facility generates itself.

(17) **System emergency** -- A condition on a utility's system that is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(18) **Transmission and distribution utility (TDU)** -- As defined in §25.5 of this title (relating to Definitions).

(d) **Negotiation and filing of rates.**

(1) **Negotiated rates or terms.** Nothing in this section shall:
   - (A) limit the authority of any PTB REP or electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differs from the rate or terms or conditions that would otherwise be required by this section; or
   - (B) affect the validity of any contract entered into between a qualifying facility and a PTB REP or electric utility for any purchase before the adoption of this section.

(2) **Filing of rates.** All rates for sales to qualifying facilities, contractual or otherwise, shall be contained in the schedule of rates of the electric utility filed with the commission.

(e) **Availability of electric utility system cost data.**

(1) **Applicability.** Paragraph (2) of this subsection applies to large electric utilities whose total sales of electric energy for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year. Paragraph (3) of this subsection applies to all other electric utilities.

(2) **Data request for large electric utilities.** Large utilities shall file the following data:
   - (A) the estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of one, ten and 100 megawatts or not more than 10% of the system peak demand for systems of less than 1,000 megawatts. The avoided cost

shall be stated on a cents-per-kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next nine years.

(B) the electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding nine years.

(C) for the current year and each of the next nine years, the estimated capacity costs at completion of the planned capacity additions and planned capacity purchases, on the basis of dollars-per-kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt-hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases. Such information shall be submitted in accordance with the Federal Energy Regulatory Commission Regulations, 18 Code of Federal Regulations, §292.302 and shall be sufficient for qualifying facilities to reasonably estimate the utility's avoided cost. Accompanying each filing pursuant to this rule shall be a detailed explanation of how the data was determined, including sources and assumptions employed.

(3) Special requirements for small electric utilities. Affected utilities shall, upon request:

(A) provide to an interested person comparable data to that required under paragraph (2) of this subsection to enable qualifying facilities to estimate the electric utility's avoided costs; or

(B) with regard to an electric utility that is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide to an interested person the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(4) **Filing date.** By February 15 each year, large electric utilities shall file with the commission and shall maintain for public inspection the data set forth in paragraph (2) of this subsection.

(f) **PTB REP and electric utility obligations.**

(1) Obligation to purchase from qualifying facilities.

(A) In accordance with this subsection and subsection (g) of this section, each PTB REP and electric utility shall purchase any energy that is made available from a qualifying facility:

(i) directly to the PTB REP or electric utility; or

(ii) indirectly to the PTB REP or electric utility in accordance with paragraph (4) of this subsection.

(B) Each electric utility shall purchase energy from a qualifying facility with a design capacity of 100 kilowatts or more within 90 days of being notified by the qualifying facility that such energy is or will be available, provided that the electric utility has sufficient interconnection facilities available. If an agreement to purchase energy is not reached within 90 days after the qualifying facility provides such notification, the agreement, if and when achieved, shall bear a retroactive effective date for the purchase of energy delivered to the electric utility correspondent with the 90th day following such notice. If the electric utility determines that adequate interconnection facilities are not available, the electric utility shall inform the qualifying facility within 30 days after being notified for distribution interconnection, or within 60 days for transmission interconnection, giving the qualifying facility a description of the additional facilities required as well as cost and schedule estimates for construction of such facilities. If an agreement to purchase energy is not reached upon completion of construction of the interconnection facilities or 90 days after notification by the qualifying facility that such energy is or will be available, the agreement, if and when achieved, shall bear a retroactive effective date for the purchase of energy delivered to the electric utility correspondent with the time of interconnection or the 90th day, whichever is later. Nothing in this subsection shall be construed in a manner that would preclude a qualifying facility from notifying and contracting for energy with a utility for sale of energy prior to 90 days before delivery of such energy.

(C) Each PTB REP shall purchase energy from a qualifying facility with a design capacity of 100 kilowatts or more within a timely fashion after being notified by the qualifying facility that such energy is or will be available.

(2) **Obligation to sell to qualifying facilities.** In accordance with subsection (k) of this section, each electric utility shall sell any energy and capacity requested to any qualifying facility located within the electric utility's service area. Each PTB REP shall also sell any energy requested to any qualifying facility; however, those sales shall be at market based rates. Nothing shall restrict the ability of any qualifying facility to purchase energy from any REP.

(3) **Interconnection.** Interconnection by a qualifying facility is addressed by Subchapter I, Division 1, of this chapter (relating to Transmission and Distribution) if the interconnection is to a transmission system and by §25.211 of this title (relating to Interconnection of On-site Distributed Generation) if the interconnection is to a distribution system, except if the interconnection is regulated by the Federal Energy Regulatory Commission.

(4) **Transmission to other electric utilities.** Transmission service provided by an electric utility in the ERCOT power region to a qualifying facility shall be governed by Subchapter I of this chapter.

(5) **PTB REP and scheduling with qualifying facilities.** A PTB REP shall use dynamic resource scheduling or responsibility transfer in ERCOT with any qualifying facility that requests such scheduling, as permitted by ERCOT. The PTB REP's cost of using dynamic resource scheduling or responsibility transfer attributable solely to purchases from qualifying facilities shall be charged to qualifying facilities that use such scheduling. If a qualifying facility uses static scheduling, the qualifying facility shall bear the costs for any imbalances resulting from the qualifying facility's failure to submit a schedule or to comply with the schedule.

(g) **Rates for purchases from a qualifying facility.**

(1) Rates for purchases of energy and capacity from any qualifying facility shall be just and reasonable to the customers of the electric utility or PTB REP and in the public interest, and shall not discriminate against qualifying cogeneration and small power production facilities.

(2) Rates for purchases of energy and capacity from any qualifying facility shall not exceed avoided cost. Rates for purchase shall be based upon a market-based determination of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchase do not violate this subsection if the rates for such purchase differ from avoided cost at the time of delivery. Payments which do not exceed avoided cost shall be found to be just and reasonable operating expenses of the electric utility.

(3) A QF may agree to commit, on a day-ahead basis, to deliver firm power for the next day to a PTB REP. Rates for purchase of this power shall be based on prices for the day that the power was actually delivered as reported or published in an independent third party index or survey of trades of commonly traded power products in ERCOT, provided that the index or survey is ERCOT-specific and is based upon enough transactions to represent a liquid market, and the commitment to deliver shall correspond with the relevant hours of delivery of those products.

(h) **Standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.**

(1) There shall be included in the tariffs of each electric utility standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. The rates for purchases under this paragraph:

(A) shall be consistent with subsection (g) of this section, as it concerns purchases from a qualifying facility;

(B) shall consider the aggregate capacity value provided by multiple qualifying facilities with a design capacity of 100 kilowatts or less; and

(C) may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(2) Terms and conditions unique to qualifying facilities with a design capacity of 100 kilowatts or less such as metering arrangements, safety equipment requirements, liability for injury or equipment damage, access to equipment and additional administrative costs, if any, shall be included in a standard tariff.

(3) The standard tariff shall offer at least the following options:

(A) parallel operation with interconnection through a single meter that measures net consumption;

(i) net consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs;

(ii) net production will not be metered or purchased by the utility and therefore there will be no additional customer charge imposed on the qualifying facility;

(B) parallel operation with interconnection through two meters with one measuring net consumption and the other measuring net production;

(i) net consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs;

(ii) net production for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) and (B) of this subsection;

(C) interconnection through two meters with one measuring all consumption by the customer and the other measuring all production by the qualifying facility;

(i) all consumption by the customer for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the customer would belong in the absence of the qualifying facility;

(ii) all production by the qualifying facility for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) and (B) of this subsection.

(4) In addition, each electric utility shall offer qualifying facilities using renewable resources with an aggregate design capacity of 50 kilowatts or less the option of interconnecting through a single meter that runs forward and backward.

(A) Any consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs.

(B) Any production for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) of this subsection.

(C) This option is not available if a contract for interconnection or the purchase of electricity is executed after December 31, 2008.

(5) Interconnection requirements necessary to permit interconnected operations between the qualifying facility and the utility and the costs associated with such requirements shall be dealt with in a manner consistent with Subchapter I of this chapter.

(6) The rates, terms and conditions contained in the standard tariff for qualifying facilities with a design capacity of 100 kilowatts or less shall be subject to review and revision by the commission.

(7) Except for qualifying facilities subject to §25.217 of this title (relating to Distributed Renewable Generation) requirements for the provision of insurance under this subsection shall be of a type

commonly available from insurance carriers in the region of the state where the customer is located and for the classification to which the customer would belong in the absence of the qualifying facility. An enhancement to a standard homeowner's or farm and ranch owner's policy containing adequate liability coverage and having the effect of adding the electric utility as an additional insured or named insured is one means of satisfying the requirements of this paragraph. Such policies shall in each instance be on a form approved or promulgated by the Texas Department of Insurance and issued by a property or casualty insurer licensed to do business in the State of Texas.

(i) **Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility.** Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility shall be filed with the commission based on one of the following approaches:

(1) Rates for purchases of nonfirm power may, by agreement of both the electric utility and the qualifying facility, be based on the utility's average avoided energy costs. Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility.

(2) PTB REPs and QFs may mutually agree to rates for purchases of nonfirm power that differ from the rates described in paragraph (4) of this subsection. Any such agreements shall be made on a nondiscriminatory basis. Such agreements may include provisions to prevent the potential for arbitrage.

(3) Rates for purchases of nonfirm power may, at the option of the qualifying facility, be based on the full cost at the time of delivery of decremental energy that would have been incurred by the electric utility had the qualifying facility not been in operation.

(A) The following factors should be considered in the calculation of the cost of decremental energy:

(i) fuel costs;
(ii) variable operating and maintenance costs;
(iii) line losses;
(iv) heat rates;
(v) cost of purchases from other sources;
(vi) other energy-related costs;
(vii) capacity costs, if, as a class, qualifying facilities providing nonfirm energy offer some predictable capacity; and
(viii) for short term energy purchases, the time and quantity of energy furnished.

(B) If practical, the avoided cost should be determined by calculating by time period, using the utility's economic dispatch model (or comparable methodology), the difference between the cost of the total energy furnished by both the qualifying facility and the utility, computed as though the energy furnished by the qualifying facility had been furnished by the utility, and the actual cost of energy furnished by the utility.

(C) The economic dispatch model should take into consideration the following factors:

(i) fuel costs;
(ii) variable operating and maintenance costs;
(iii) line losses;
(iv) heat rates;
(v) purchased power opportunity;
(vi) system stability; and
(vii) operating characteristics.

(D) Time periods should be hourly if the utility has an automated economic dispatch model available; otherwise the shortest reasonable time period for which costs can be determined should be used.

(E) Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility.

(4) Rates for purchases of nonfirm power shall be based on the market price of energy at the time of sale from the QF unless other arrangements have been made in accordance with paragraph (2) of this subsection. Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility. Such agreements may include provisions to prevent the potential for arbitrage.

(j) **Periods during which purchases not required.**

(1) Any PTB REP or electric utility which gives notice to each affected qualifying facility in time for the qualifying facility to cease delivery of energy or capacity to the PTB REP, or electric utility will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, including resource ramp rate limitations that could cause imbalances or the amount of energy put by the QF exceeds the PTB REP's load, purchases from qualifying facilities will result in costs greater than those which the electric utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself, provided, however, that this subsection does not override contractual obligations of the PTB REP or electric utility to purchase from a qualifying facility.

(2) Any PTB REP or electric utility which fails to give notice to each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the PTB REP or electric utility will be required to pay the same rate for such purchase of energy or capacity as would be required had the period of greater costs not occurred.

(3) A claim by PTB REP or an electric utility that such a period has occurred or will occur is subject to such verification by the commission either before or after the occurrence.

(k) **Rates for sales to qualifying facilities.**

(1) General rules.

(A) Rates for sales to qualifying facilities shall be just and reasonable and in the public interest, and shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. Rates for standby or other supplementary service shall be based on the amount of capacity contracted for between the qualifying facility and the electric utility, and shall not penalize electric utilities that also purchase power from qualifying facilities. The need for and cost responsibility for special equipment or system modifications shall be determined by application of Subchapter I of this chapter.

(B) Rates for sales that are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the electric utility's other customers with similar load or other cost-related characteristics.

(2) Additional services to be provided to qualifying facilities.

(A) Upon request of a qualifying facility within its service area, each electric utility shall provide:

(i) supplementary power;

(ii) back-up power;

(iii) maintenance power; and

(iv) interruptible power.

(B) An electric utility shall not be required to provide supplementary power, back-up power, or maintenance power to a qualifying facility if the commission finds that provision of such power will:

(i) impair the electric utility's ability to render adequate service to its customers; or
(ii) place an undue burden on the electric utility.

(3) Rates for sales of back-up power and maintenance power. The rate for sales of back-up power or maintenance power:
(A) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and
(B) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

(l) **System emergencies.**

(1) **Qualifying facility obligation to provide power during system emergencies.** A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:
(A) provided by agreement between such qualifying facility and electric utility; or
(B) ordered under the Federal Power Act, §202(c).

(2) **Discontinuance of purchases and sales during system emergencies.** During any system emergency, an electric utility may discontinue:
(A) purchases from a qualifying facility if such purchases would contribute to such emergency; and
(B) sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

(m) **Enforcement.** A proceeding to resolve a dispute between an electric utility, PTB REP and a qualifying facility arising under this section may be instituted by filing of a petition with the commission. Electric utilities, PTB REPs, and qualifying facilities are encouraged to engage in alternative dispute resolution prior to the filing of a complaint.

§25.243. Distribution Cost Recovery Factor (DCRF).

(a) Purpose and application. This section implements Public Utility Regulatory Act (PURA) §36.210. This section applies to electric utilities, including transmission and distribution utilities (TDUs), that provide wholesale or retail distribution service.

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

(1) **Capitalized operations and maintenance expenses** -- Expenses that have been deferred or amortized as a regulatory asset or liability.

(2) **DCRF proceeding** -- A proceeding conducted pursuant to this section in which creation or amendment of a DCRF is considered on application of an electric utility to the commission pursuant to subsection (c)(1) of this section.

(3) **Distribution invested capital** -- The parts of the electric utility's invested capital, as described in PURA §36.053, that are categorized as distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks properly recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 352, 353, 360 through 374, 391, and 397. Distribution invested capital includes only costs: for plant that has been placed into service; that comply with PURA, including §36.053 and §36.058; and that are prudent, reasonable, and necessary. Distribution invested capital does not include: generation-related costs; transmission-related costs, including costs recovered through rates set pursuant to §25.192 of this title (relating to Transmission Service Rates), §25.193 of this title (relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)), or §25.239 of this title (relating to Transmission Cost Recovery Factor for Certain Electric Utilities); indirect corporate costs; capitalized operations and maintenance expenses; and distribution invested capital recovered through a separate rate, including a surcharge, tracker, rider, or other mechanism. In a DCRF proceeding, an electric utility may elect not to seek recovery of certain distribution invested capital, but may not exclude all of the distribution invested capital in one of the accounts identified above unless the electric utility can prove that the distribution invested capital in the account reduced by the related accumulated depreciation is greater than the distribution invested capital in the account reduced by the related accumulated depreciation used in setting rates in the electric utility's last comprehensive base-rate proceeding.

(4) Net distribution invested capital -- Distribution invested capital less accumulated depreciation and adjusted for any changes in distribution-related accumulated deferred federal income taxes and excluding any impact associated with Financial Accounting Standards Board Interpretation No. 48 (FIN 48).

(5) Weather-normalized -- Adjusted for normal weather using weather data for the most recent ten calendar years.

(c) Application for a DCRF.

(1) **General requirements.**

(A) **Filing of application.** An electric utility may apply for inclusion of a DCRF in its tariffs for wholesale and retail distribution service. To implement a DCRF, an electric utility shall file the application for the DCRF simultaneously with all regulatory authorities having original jurisdiction over the electric utility's distribution service area.

(B) **Municipal proceedings.** A municipality's governing body with original jurisdiction over an application for a DCRF shall make a final decision on the application within 60 days after the application was filed. If the governing body does not make a final decision within 60 days after the application was filed, the application is deemed denied by the governing body. On the 60th day after the application is filed, the electric utility is deemed to appeal the governing body's final decision to the commission, regardless of whether the governing body approves or denies the application, and the appeal is deemed at that time to be consolidated with the electric utility's DCRF proceeding before the commission. In addition, the governing body's interim and final decisions are deemed automatically suspended at the times they took effect.

(C) **Frequency of DCRF proceedings.** An electric utility may have no more than one DCRF (including a DCRF amendment) become effective each calendar year pursuant to an application filed pursuant to this paragraph. An electric utility may change its rates pursuant to a DCRF no more than four times between comprehensive base-rate proceedings. An electric utility shall not apply for a DCRF while a comprehensive base-rate proceeding for the electric utility is pending. In addition, the presiding officer shall dismiss an electric utility's application for a DCRF if the electric utility or commission initiates a comprehensive base-rate proceeding within 145 days after the electric utility filed the application for a DCRF.

(2) Requirements applicable to TDUs. A TDU may file an application for a DCRF only during the period April 1 through April 8. A TDU shall not file an application for a DCRF after April 8 of a year even if April 8 is not a working day, as defined by §22.2(44) of this title (relating to Definitions).

(3) Requirements applicable to other electric utilities. An electric utility that does not offer customer choice may file an application for a DCRF at any time other than in April and May.

(d) **Calculation of DCRF.**

(1) **DCRF formula.** The DCRF for each rate class shall be calculated using the following formula:

$$[((DIC_C - DIC_{RC}) * ROR_{AT}) + (DEPR_C - DEPR_{RC}) + (FIT_C - FIT_{RC}) + (OT_C - OT_{RC}) - \sum(DISTREV_{RC\text{-}CLASS} * \%GROWTH_{CLASS})] * ALLOC_{CLASS} / BD_{C\text{-}CLASS}$$

Where:

DIC_C = Current Net Distribution Invested Capital.

DIC_{RC} = Net Distribution Invested Capital from the last comprehensive base-rate proceeding.

ROR_{AT} = After-Tax Rate of Return as defined in paragraph (2) of this subsection.

$DEPR_C$ = Current Depreciation Expense, as related to Current Gross Distribution Invested Capital, calculated using the currently approved depreciation rates.

$DEPR_{RC}$ = Depreciation Expense, as related to Gross Distribution Invested Capital, from the last comprehensive base-rate proceeding.

FIT_C = Current Federal Income Tax, as related to Current Net Distribution Invested Capital, including the change in federal income taxes related to the change in return on rate base and synchronization of interest associated with the change in rate base resulting from additions to and retirements of distribution plant as used to compute Net Distribution Invested Capital.

FIT_{RC} = Federal Income Tax, as related to Net Distribution Invested Capital from the last comprehensive base-rate proceeding.

OT_{C} = Current Other Taxes (taxes other than income taxes and taxes associated with the return on rate base), as related to Current Net Distribution Invested Capital, calculated using current tax rates and the methodology from the last comprehensive base-rate proceeding, and not including municipal franchise fees.

OT_{RC} = Other Taxes, as related to Net Distribution Invested Capital from the last comprehensive base-rate proceeding, and not including municipal franchise fees.

$DISTREV_{RC\text{-}CLASS}$ (Distribution Revenues by rate class based on Net Distribution Invested Capital from the last comprehensive base-rate proceeding) = ($DIC_{RC\text{-}CLASS}$ * ROR_{AT}) + $DEPR_{RC\text{-}CLASS}$ + $FIT_{RC\text{-}CLASS}$ + $OT_{RC\text{-}CLASS.}$

$\%GROWTH_{CLASS}$ (Growth in Billing Determinants by Class) = ($BD_{C\text{-}CLASS}$ – $BD_{RC\text{-}CLASS}$) / $BD_{RC\text{-}CLASS}$

$DIC_{RC\text{-}CLASS}$ = Net Distribution Invested Capital allocated to the rate class from the last comprehensive base-rate proceeding.

$DEPR_{RC\text{-}CLASS}$ = Depreciation Expense, as related to Gross Distribution Invested Capital, allocated to the rate class in the last comprehensive base-rate proceeding.

$FIT_{RC\text{-}CLASS}$ = Federal Income Tax, as related to Net Distribution Invested Capital, allocated to the rate class in the last comprehensive base-rate proceeding.

$OT_{RC\text{-}CLASS}$ = Other Taxes, as related to Net Distribution Invested Capital, allocated to the rate class in the last comprehensive base-rate proceeding, and not including municipal franchise fees.

$ALLOC_{CLASS}$ = Rate Class Allocation Factor approved in the last comprehensive base-rate proceeding, calculated as: total net distribution plant allocated to rate class, divided by total net distribution plant. For situations in which data from the last comprehensive base-rate proceeding are not available to perform the described calculation, the Rate Class Allocation Factor shall be calculated as the total distribution revenue requirement allocated to the rate class (less any identifiable amounts explicitly unrelated to Distribution Invested Capital) divided by the total distribution revenue requirement (less any identifiable amounts explicitly unrelated to Distribution Invested Capital) for all classes as approved by the commission in the electric utility's last comprehensive base-rate case.

$BD_{C\text{-}CLASS}$ = Rate Class Billing Determinants (weather-normalized and adjusted to reflect the number of customers at the end of the period) for the 12 months ending on the date used for purposes of determining the Current Net Distribution Invested Capital. For customer classes billed primarily on the basis of kilowatt-hour billing determinants, the DCRF shall be calculated using kilowatt-hour billing determinants. For customer classes billed primarily on the basis of demand billing determinants, the DCRF shall be calculated using demand billing determinants.

$BD_{RC\text{-}CLASS}$ = Rate Class Billing Determinants used to set rates in the last comprehensive base-rate proceeding.

If an input to the DCRF formula from the last comprehensive base-rate proceeding is not separately identified in that proceeding, it shall be derived from information from that proceeding.

(2) **Return on invested capital.** The electric utility's rate of return is the rate of return approved by the commission in the electric utility's last comprehensive base-rate proceeding if the final order (which may be an order on rehearing) approving the rate of return was filed less than three years before the application for a DCRF was filed. If the final order approving the rate of return was filed three years or more before the application for a DCRF was filed, the rate of return is the

lesser of the rate of return in the final order or the alternative rate of return calculated as follows: The alternative rate of return shall be calculated using a 10% cost of equity, the capital structure approved by the commission in the electric utility's last comprehensive base-rate proceeding, and the cost of debt as reported in the electric utility's most recent Earnings Monitoring Report filed pursuant to §25.73 of this title (relating to Financial and Operating Reports).

(3) **Determination of Distribution Invested Capital.** The electric utility must clearly identify any costs included as distribution invested capital because of a change in accounting rules or practices since the test year in the electric utility's most recent comprehensive base-rate proceeding. The commission shall exclude such costs if the electric utility does not prove that the costs are appropriate for recovery through the DCRF.

(e) **Procedures for DCRF proceeding.**

(1) Filing requirements. To file an application for a DCRF, an electric utility shall use the commission-prescribed form and include a sworn statement from an appropriate employee of the electric utility that the application complies with the electric utility's tariff and this section, including that the distribution invested capital in the application includes only costs: for plant that has been placed into service; that comply with PURA, including §36.053 and §36.058; and that are prudent, reasonable, and necessary. In addition, the sworn statement shall state that the application is true and correct to the best of the employee's knowledge, information, and belief. Furthermore, the electric utility shall include in its application an earnings monitoring report for the immediately preceding calendar year prepared in accordance with §25.73(b) of this title.

(2) Notice and intervention deadline. By the day after it files its application, the electric utility shall provide notice of its application, using a reasonable method of notice, to all parties in the electric utility's last comprehensive base-rate proceeding and, if applicable, last DCRF proceeding, and shall include in the notice the docket number for the new proceeding. The intervention deadline is 30 days from the date service of notice is completed.

(3) Parties. The Office of Public Utility Counsel and affected parties may participate as parties in a DCRF proceeding.

(4) Denial due to earnings. The commission shall deny an electric utility's application for a DCRF if the earnings monitoring report included in the electric utility's application shows that the electric utility is earning more than its authorized rate of return using weather-normalized data. In making this determination, the commission shall correct the calculation of the earned rate of return in the earnings monitoring report to the extent that the calculation does not comply with §25.73(b) of this title and any form adopted to implement that subsection.

(5) Scope of proceeding. The issues of whether distribution invested capital included in an application for a DCRF or DCRF adjustment complies with PURA, including §36.053 and §36.058, and is prudent, reasonable, and necessary shall not be addressed in a DCRF proceeding unless the presiding officer finds that good cause exists to address these issues.

(6) Commission processing of application.

(A) **Sufficiency of application.** A motion to find an application materially deficient shall be filed no later than 30 days after service of notice is completed. The motion shall be served on the electric utility by hand delivery, facsimile transmission, or overnight courier delivery, or by e-mail if agreed to by the electric utility or ordered by the presiding officer. The motion shall specify the nature of the deficiency and the relevant portions of the application, and cite the particular requirement with which the application is alleged not to comply. The electric utility's response to a motion to find an application materially deficient shall be filed no later than five working days after such motion is received. If within ten working days after the deadline for filing a motion to find an application materially deficient, the presiding officer has not issued a written order concluding that material deficiencies exist in the application, the application is deemed sufficient.

(B) Discovery. Each party, other than commission staff, may serve no more than 20 requests for information and requests for admissions of fact pursuant to §22.144 of this title (relating to Requests for Information and Requests for Admission of Facts), except where the presiding officer finds good cause for a party to serve additional requests. Except for a request by commission staff, a request shall not include subparts or multiple questions, and requests shall be sequentially numbered, regardless of whether the requests are served at the same time or on different parties. A response to a request shall be served no later than ten working days after receipt of the discovery request. An objection to a request shall be filed no later than five working days from receipt of the request. A request for which an objection is filed does not count towards a party's request limit. A party may request a technical conference by the intervention deadline, and shall identify the topics that it wants to discuss. An electric utility shall hold the technical conference in Austin, Texas five working days after the intervention deadline, unless the electric utility and the parties who requested the technical conference agree to a different date. The technical conference shall be held at the location designated by the electric utility, unless the commission staff designates a location. The electric utility shall have appropriate persons attend the technical conference to answer questions. A party may take a deposition only if authorized by the presiding officer.

(C) System-wide rates and effective date of DCRF. The presiding officer shall approve the DCRF for an electric utility on a system-wide basis and set the effective date of the DCRF for a TDU as September 1 unless good cause exists for a later date. The presiding officer shall make a final decision on a DCRF application made by a TDU at least 46 days before the effective date of the approved rates, even if this requirement results in an effective date after September 1. For an electric utility that does not offer customer choice, the presiding officer shall set the effective date of the DCRF to be 145 days after the application was filed unless good cause exists for a later date.

(D) Review of application. A DCRF proceeding is eligible for disposition pursuant to §22.35(b)(1) of this title (relating to Informal Disposition).

(E) Notice of approved rates. Unless otherwise ordered, a TDU shall serve notice of the approved rates and the effective date of the approved rates by the working day after the presiding officer's final decision, to retail electric providers that are authorized by the registration agent to provide service in the TDU's distribution service area. Notice under this subparagraph of this paragraph may be served by email.

(f) **DCRF reconciliation.** The commission shall reconcile investments recovered through a DCRF in the electric utility's next comprehensive base-rate proceeding to the extent such reconciliation did not already occur in a DCRF proceeding pursuant to subsection (e)(5) of this section. The reconciliation shall be limited to the issues of the extent to which the investments complied with PURA, including §36.053 and §36.058, and this section and were prudent, reasonable, and necessary. To the extent that the commission determines that the investments did not comply with PURA and this section or were not prudent, reasonable, and necessary, the electric utility shall refund all revenues related to the investments that it improperly recovered through rates, and shall also pay its customers carrying charges on these revenues. The carrying charges shall be determined as follows: For the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the new base rates, carrying costs shall be calculated using the same rate of return that was applied to the investments in the DCRF proceedings that resulted in the over-recovery. For the time period beginning with the effective date of the new base rates, carrying costs shall be calculated using the electric utility's rate of return authorized in the comprehensive base-rate proceeding.

(g) **DCRF's effect on electric utility's financial risk and rate of return.** In setting the rate of return for an electric utility with a DCRF, the commission may expressly consider the effect of the DCRF on the electric utility's financial risk and rate of return.

(h) **Reports**. An electric utility with a DCRF shall file reports that will permit the commission to monitor its DCRF revenues, in accordance with any filing requirements and schedules prescribed by the commission pursuant to §25.73 of this title or this section.

(i) **Expiration.** This section expires upon the expiration of PURA §36.210. Any DCRF in effect at that time shall remain in effect until the electric utility's next comprehensive base-rate proceeding.

§25.244. Billing Demand for Certain Utility Customers.

(a) **Application**. This section applies to a transmission and distribution utility (TDU) that provides retail distribution service.

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

(1) **Demand ratchet --** A provision in a TDU's tariff for retail distribution service that allows a customer to be billed based on the greater of the peak demand by that customer in the current month or some fixed percentage of the peak demand for that customer during previous months.

(2) **Nonresidential secondary voltage service customer --** A nonresidential customer that is billed demand charges for retail distribution service and that receives retail distribution service at secondary voltage through one point of delivery and that is measured using one meter.

(c) **Rates**. In a proceeding in which base rates are set for nonresidential secondary voltage service customers, the base rates set for nonresidential secondary voltage service customers shall provide that these customers shall be billed on a kilowatt-hour (kWh), kilowatt (kW), or kilovolt-amperes (kVA) basis, and that if a demand ratchet is utilized, the demand ratchet shall not apply to a nonresidential secondary voltage service customer that has an annual load factor less than or equal to 25 percent. This subsection does not require the use of demand ratchets for any customers. This subsection shall not be applied in a manner that would shift costs to other customer classes.

(d) **Annual Verification**. Upon the implementation of base rates consistent with subsection (c) of this section, a TDU shall determine annually for each of its nonresidential secondary service customers whether to apply a demand ratchet. In addition, by January 15 of each year following the commission's final order in a proceeding described by subsection (c) of this section, a TDU shall file an affidavit certifying that it has accurately identified and billed nonresidential secondary service customers who under subsection (c) of this section cannot be charged a demand ratchet. In addition, the TDU shall attach to the affidavit a thorough description of the procedures that it uses to ensure that these customers are accurately identified and billed.

§25.245. Rate-Case Expenses.

(a) **Application.** This section applies to utilities requesting recovery of expenses for ratemaking proceedings (rate-case expenses) pursuant to Public Utility Regulatory Act (PURA) §36.061(b)(2) and to municipalities requesting reimbursement for rate-case expenses pursuant to PURA §33.023(b).

(b) **Requirements for claiming recovery of or reimbursement for rate-case expenses.** A utility or municipality requesting recovery of or reimbursement for its rate-case expenses shall have the burden to prove the reasonableness of such rate-case expenses by a preponderance of the evidence. A utility or municipality seeking recovery of or reimbursement for rate-case expenses shall file sufficient information that details and itemizes all rate-case expenses, including, but not limited to, evidence verified by testimony or affidavit, showing:

(1) the nature, extent, and difficulty of the work done by the attorney or other professional in the rate case;

(2) the time and labor required and expended by the attorney or other professional;

(3) the fees or other consideration paid to the attorney or other professional for the services rendered;

(4) the expenses incurred for lodging, meals and beverages, transportation, or other services or materials;

(5) the nature and scope of the rate case, including:

(A) the size of the utility and number and type of consumers served;

(B) the amount of money or value of property or interest at stake;

(C) the novelty or complexity of the issues addressed;

(D) the amount and complexity of discovery;

(E) the occurrence and length of a hearing; and

(6) the specific issue or issues in the rate case and the amount of rate-case expenses reasonably associated with each issue.

(c) **Criteria for review and determination of reasonableness.** In determining the reasonableness of the rate-case expenses, the presiding officer shall consider the relevant factors listed in subsection (b) of this section and any other factor shown to be relevant to the specific case. The presiding officer shall decide whether and the extent to which the evidence shows that:

(1) the fees paid to, tasks performed by, or time spent on a task by an attorney or other professional were extreme or excessive;

(2) the expenses incurred for lodging, meals and beverages, transportation, or other services or materials were extreme or excessive;

(3) there was duplication of services or testimony;

(4) the utility's or municipality's proposal on an issue in the rate case had no reasonable basis in law, policy, or fact and was not warranted by any reasonable argument for the extension, modification, or reversal of commission precedent;

(5) rate-case expenses as a whole were disproportionate, excessive, or unwarranted in relation to the nature and scope of the rate case addressed by the evidence pursuant to subsection (b)(5) of this section; or

(6) the utility or municipality failed to comply with the requirements for providing sufficient information pursuant to subsection (b) of this section.

(d) C**alculation of allowed or disallowed rate-case expenses.**

(1) Based on the factors and criteria in subsections (b) and (c) of this section, the presiding officer shall allow or recommend allowance of recovery of rate-case expenses equal to the amount shown in the evidentiary record to have been actually and reasonably incurred by the requesting utility or

municipality. The presiding officer shall disallow or recommend disallowance of recovery of rate-case expenses equal to the amount shown to have been not reasonably incurred under the criteria in subsection (c) of this section. A disallowance may be based on cost estimates in lieu of actual costs if reasonably accurate and supported by the evidence.

(2) A disallowance pursuant to subsection (c)(5) of this section may be calculated as a proportion of a utility's or municipality's requested rate-case expenses using the following methodology or any other appropriate methodology:

(A) For utilities, the ratio of:

(i) the amount of the increase in revenue requirement requested by the utility that was denied, to

(ii) the total amount of the increase in revenue requirement requested in a proceeding by the utility.

(B) For municipalities, the ratio of:

(i) the amount of the increase in revenue requirement requested by the utility unsuccessfully challenged by the municipality, to

(ii) the total amount of the increase in revenue requirement challenged by the municipality.

(3) If the evidence presented pursuant to subsection (b)(6) of this section does not enable the presiding officer to determine the appropriate disallowance of rate-case expenses reasonably associated with an issue with certainty and specificity, then the presiding officer may disallow or deny recovery of a proportion of a utility's or municipality's requested rate-case expenses using the following methodology or any other appropriate methodology:

(A) For utilities, the ratio of:

(i) the amount of the increase in revenue requirement requested by the utility in the rate case related to the issue(s) not reasonably supported by evidence of certainty and specificity, to

(ii) the total amount of the increase in revenue requirement requested in a proceeding by the utility.

(B) For municipalities, the ratio of:

(i) the amount of the increase in revenue requirement requested by the utility in the rate case challenged by the municipality relating to the issue(s) not reasonably supported by evidence of certainty and specificity, to

(ii) the total amount of the increase in revenue requirement challenged by the municipality.

§25.246. Rate Filing Standards and Procedures for Non-ERCOT Utilities.

(a) **Application.** The provisions of this section apply only to an electric utility that operates solely outside of the Electric Reliability Council of Texas.

(b) **Adjustments to test year information.**

(1) **Definitions.**

(A) **Test year --** The period defined in §25.5(134) of this title (relating to Definitions).

(B) **Update period** -- For a utility that elects to file under paragraph (2)(B) of this subsection, the period beyond the end of the test year, for which period the electric utility initially submits estimated information and later submits actual information to be used in establishing its base rates. The update period chosen by the utility must end on the last day of a calendar or fiscal year quarter, and not later than the 30th day before the date the applicable rate proceeding is filed.

(2) **Test year election.** In establishing the base rates of an electric utility under the Public Utility Regulatory Act (PURA), Chapter 36, Subchapter C or D, the commission shall determine the utility's revenue requirement based on, at the election of the utility:

(A) information submitted for a test year; or

(B) information submitted for a test year updated to include actual information for the update period regarding increases and decreases in the utility's cost of service, including expenses, capital investment, cost of capital, and sales.

(3) **Requirements for test year update.** The updated information authorized to be submitted by paragraph (2)(B) of this subsection shall be subject to the following additional standards:

(A) expenses authorized by §25.231(b) of this title (relating to Cost of Service) for inclusion in revenue requirement shall reflect the 12-month period ending on the final day of the update period;

(B) components of rate base as defined by §25.231(c)(2) of this title shall be included through the end of the update period;

(C) the electric utility's cost of capital shall be updated to reflect any transactions affecting those items that occur between the end of the test year and the end of the update period; and

(D) the utility's sales revenues, customer count, and billing determinants shall reflect the 12-month period ending on the final day of the update period.

(4) **Use of estimates; supplementation of information.**

(A) An electric utility that includes estimated information for the update period in the initial filing of a rate proceeding shall supplement that filing with actual information not later than the 45th day after the date the initial filing was made. The update must provide actual information for all information originally estimated. The utility shall update every component of its cost of service that changed, including flow-through effects and attendant impacts of changes. The utility need not, however, update or refile every piece of information in the originally filed case. The utility shall file the entire update on a single business day.

(B) The commission shall extend the deadline for concluding the rate proceeding for a period of time equal to the period between the date the initial filing of the proceeding was made and the date of the supplemental filing made under subparagraph (A) of this paragraph, except that the extension period may not exceed 45 days.

(5) **Known and measurable changes.** In establishing the base rates of an electric utility, an electric utility that makes an election under paragraph (2) of this subsection is not precluded from

proposing known and measurable adjustments to the utility's historical rate information as permitted by PURA and the commission's rules.

(6) **Post-test year adjustment for newly constructed or acquired natural-gas-fired power plant.** In addition to the test year update authorized by paragraph (2)(B) of this subsection, and without limiting the availability of known and measurable adjustments otherwise permitted by PURA and commission rules, the commission shall allow an electric utility to make a known and measurable adjustment for a newly constructed or acquired natural-gas-fired generation facility.

(A) The commission is required to allow a known and measurable adjustment under this paragraph only if the natural-gas-fired generation facility is in service before the effective date of new rates.

(B) A known and measurable adjustment under this paragraph shall include the utility's prudent capital investment in the facility, a reasonable return on such capital investment, depreciation expense, reasonable and necessary operating expenses, and all attendant impacts associated with the newly constructed or acquired natural-gas-fired generation facility, including any offsetting revenue, as determined by the commission.

(C) Notwithstanding the requirements of §25.231(c)(2)(F)(i)(II) of this title, the commission shall allow an adjustment under this paragraph regardless of whether the investment is less than 10% of the utility's rate base before the date of the adjustment.

(c) **Requirement to initiate rate proceeding.**

(1) **Timing.** An electric utility is required to make filings with regulatory authorities as required by PURA, Chapter 33, Subchapter B, and shall file a rate-filing package under PURA, Chapter 36, Subchapter D, to initiate a comprehensive base rate proceeding before all of the utility's regulatory authorities in the following circumstances:

(A) on or before the fourth anniversary of the date of the final order in the utility's most recent comprehensive base rate proceeding; or

(B) if the commission determines, before the deadline described in subparagraph (A) of this paragraph, that the utility has earned materially more than the utility's authorized rate of return on investment, on a weather-normalized basis, in the utility's two most recent consecutive commission earnings monitoring reports.

(C) If a rate-filing package is required to be submitted under this subsection, the utility's rate filing shall reflect a test year, which at the election of the utility may be updated pursuant to subsection (b)(2)(B) of this section, and may be otherwise adjusted for known and measurable changes as permitted by PURA and commission rules.

(2) **Extension of rate-case-filing deadline.** A utility is required to make a rate filing by the deadline set forth in paragraph (1)(A) of this subsection unless the commission grants an extension of the deadline. The commission may extend the deadline set forth in paragraph (1)(A) of this subsection and set a new deadline if the commission determines that a comprehensive base rate case would not result in materially different rates. The utility shall have the burden to prove that a delay in the rate-case-filing deadline is warranted and shall submit all requisite information to meet such burden.

(A) On or before the third anniversary of the date of the final order in the utility's most recent comprehensive base rate proceeding, the utility shall submit a filing to the commission indicating whether the utility seeks an extension to the deadline described in paragraph (1)(A) of this subsection. If the utility seeks an extension, at the time of such filing it shall provide all relevant information to meet its burden in showing that an extension is justified. The commission shall give interested parties a reasonable opportunity to present materials and argument before making a determination under this paragraph; the Administrative Law Judge(s) assigned to the docket concerning the extension shall set procedural guidelines, including discovery limits and deadlines allowing the commission sufficient time to provide notice pursuant to paragraph (3)(A)(i) of this subsection.

(B) **Standard of review.** In determining whether to extend the time period for the filing of a base rate proceeding, the commission may consider matters such as the following:

(i) the results of recent earnings monitoring reports for the utility, including such adjustments to those reports as may be found appropriate by the commission;

(ii) recent and expected levels of expenses, sales revenues, and capital investment for the utility;

(iii) recent and projected financial results for the utility;

(iv) continued appropriateness of the utility's allocation of costs and rate design;

(v) capital market conditions;

(vi) whether there has been a material change in circumstances since the utility's base rates were last established by the commission; and

(vii) any other factors the commission deems relevant to its determination.

(3) **Notice.**

(A) **Notice to the utility.** The utility must make the filings described in paragraph (1) of this subsection not later than the 120th day after the date the commission provides written notice to the utility:

(i) that a filing under paragraph (1)(A) of this subsection will be required; or

(ii) that the condition of material over-earning described by paragraph (1)(B) of this subsection exists. The 120-day period provided by this subsection may be extended by the commission for good cause.

(B) **Notice to parties.** If the utility seeks an extension to the filing deadline pursuant to paragraph (2) of this subsection, the utility shall provide, at the time the utility submits its filing to the commission requesting an extension, notice to all persons who were parties to the utility's most recent base rate proceeding.

(d) **Relation back of rates.**

(1) In a rate proceeding under PURA, Chapter 36, Subchapter D, or if requested by an electric utility in the utility's statement of intent initiating a rate proceeding under PURA, Chapter 36, Subchapter C, notwithstanding PURA §36.109(a), the final rate set in the proceeding, whether a rate increase or rate decrease, shall be made effective for consumption on and after the 155th day after the date the rate-filing package is filed. Unless the commission approves temporary rates under PURA §36.109(a), the utility's new rates will not be implemented until the commission issues its final order approving new rates.

(2) The commission shall:

(A) require the electric utility to refund to customers money collected in excess of the rate finally ordered on or after the 155th day after the date the rate-filing package is filed; or

(B) authorize the electric utility to collect a surcharge from customers to recover the amount by which the money collected on or after the 155th day after the utility files its rate-filing package is less than the money that would have been collected under the rate finally ordered.

(3) The commission may require refunds or surcharges of amounts determined under paragraph (2) of this subsection over a period not to exceed 18 months, along with appropriate carrying costs. The commission shall make any adjustments necessary to prevent over-recovery of amounts reflected in riders in effect for the electric utility during the pendency of the rate proceeding. Customers who receive service at transmission voltage levels, as well as any groups of seasonal agricultural customers as identified by the electric utility, shall be subject to refund or surcharge rates calculated based upon their individual historical usage and demand recorded during each month in

the period in which the refund or surcharge obligation arose, adjusted for line losses if necessary. All other customers shall be subject to refund or surcharge rates calculated based upon the historical usage and demand of all customers served under the same tariffed rate schedule recorded during each month in the period in which the refund or surcharge obligation arose, adjusted for line losses if necessary.

(4) An electric utility may not assess more than one surcharge authorized by paragraph (2)(B) of this subsection at the same time.

§25.247. Rate Review Schedule.

(a) **Application.** This section applies only to an electric utility, other than a river authority, that operates solely inside the Electric Reliability Council of Texas (ERCOT).

(b) **Filing requirements.**

(1) Each electric utility in the ERCOT region must file for a comprehensive rate review within 48 months of the order setting rates in its most recent comprehensive rate proceeding or other proceeding in which the commission approved a settlement agreement reflecting a rate modification that allowed the electric utility to avoid the filing of such a rate case. For a transmission and distribution utility, the filing must include information necessary for the review of both transmission and distribution rates.

(2) On a year-to-year basis, the commission shall issue an order extending the filing requirements under paragraph (1) of this subsection by one year if the following conditions are met:

(A) for an electric utility providing transmission-only service, the utility's most recent earnings monitoring report, as of 180 days before its scheduled filing date established by this section, filed in compliance with commission rules and instructions or as adjusted by the commission to conform with the rules and instructions, shows that it is earning, on a weather-normalized basis using weather data for the most recent ten calendar years, less than 50 basis points above the average of the most recent commission-approved rate of return on equity for each transmission-only utility operating in ERCOT; or

(B) for a transmission and distribution utility, the utility's most recent earnings monitoring report, as of 180 days before its scheduled filing date established by this section, filed in compliance with commission rules and instructions or as adjusted by the commission to conform with the rules and instructions, shows that it is earning, on a weather-normalized basis using weather data for the most recent ten calendar years, less than 50 basis points above the average of the most recent commission-approved rate of return on equity for each transmission and distribution utility operating in ERCOT with at least 175,000 metered customers.

(3) The commission may extend the scheduled filing deadline under paragraphs (1) and (2) of this subsection for good cause shown or because of resource constraints of the commission.

(4) An electric utility qualifying for an extension under paragraph (2) of this subsection shall submit notice in the same project as the filing of its most recent earnings monitoring report at least 180 days before the fourth anniversary of the order in its most recent comprehensive rate proceeding or other proceeding in which the commission approved a settlement agreement reflecting a rate modification that allowed the electric utility to avoid the filing of such a rate case.

(5) Nothing in this section limits the commission's authority to initiate a rate proceeding at any time under this title on the basis of other criteria that the commission determines are in the public interest, including but not limited to the information provided in an electric utility's earnings monitoring report.

(c) **Transition issues for electric utilities.**

(1) If an electric utility subject to subsection (a) of this section has a comprehensive rate proceeding pending on the effective date of this rule, the electric utility is required to file, after the commission's final order in that pending proceeding, a comprehensive rate proceeding in accordance with subsection (b) of this section. If the pending proceeding is withdrawn, dismissed, or otherwise resolved without a final order, the electric utility shall be subject to the transition timelines in paragraph (2) of this subsection unless the commission orders otherwise.

(2) All electric utilities subject to subsection (a) of this section shall make their initial filings under this section on or before the later of:

(A) 48 months from the order in the electric utility's last comprehensive rate proceeding or other proceeding in which the commission approved a settlement agreement reflecting a rate modification that allowed the electric utility to avoid the filing of such a rate case; or

(B) the following dates:

Texas-New Mexico Power Company	August 31, 2018
AEP Texas, Inc.	May 1, 2019
CenterPoint Energy Houston Electric, LLC	July 1, 2019
Wind Energy Transmission Texas, LLC	October 1, 2019
Cross Texas Transmission, LLC	February 3, 2020
Sharyland Utilities, LP and Sharyland Distribution & Transmission Services, LLC	July 1, 2020
Lone Star Transmission, LLC	September 1, 2020
Electric Transmission Texas, LLC	February 1, 2021
Oncor Electric Delivery Company, LLC	October 1, 2021

§25.251. Renewable Energy Tariff.

(a) **Purpose.** This section allows electric utilities to offer a renewable energy tariff to all retail customers. The purpose of the renewable energy tariff is to use market-based methods to promote the use of renewable energy technologies to supply electricity to Texas, to protect and enhance the quality of Texas' environment, and to respond to customers' expressed preferences for renewable resources.

(b) **Application**. This section applies to electric utilities as defined in the Public Utility Regulatory Act (PURA) §31.002(1) choosing to offer a tariff under this section.

(c) **Definitions.**
  (1) **Existing renewable resources —** Renewable resources that are in operation on the effective date of this rule.
  (2) **New resources —** Renewable resources placed in service after the effective date of this rule.
  (3) **Renewable energy —** Energy derived from renewable energy technologies as defined in §25.5 of this title (relating to Definitions).
  (4) **Renewable energy premium —** The sum of the purchase cost per kWh of renewable energy acquired to serve customers under this tariff minus the average embedded cost per kWh of the utility's existing generation and purchased resources outside this tariff, plus the appropriate per kWh cost of renewable energy tariff marketing and administrative activities pursuant to subsection (l)(1) of this section.
  (5) **Renewable energy price —** The sum of the utility's average delivered retail cost per kWh for its embedded mix of energy and capacity from all resources excluding those acquired for this tariff, and the renewable energy premium as defined in paragraph (4) of this subsection.

(d) **Eligible renewable resources.** Except where specifically noted, renewable resources that are acceptable under this tariff shall meet the following requirements:
  (1) **Renewable energy resource.** A renewable energy resource eligible under this tariff must meet the requirements of subsection (c)(3) of this section.
  (2) **New and existing resources.** A new or existing resource is eligible if its costs have not been placed in any utility's rates or in a purchase power cost recovery factor (PCRF) as of the effective date of this rule.
  (3) **Repowered or retrofitted projects**. The incremental energy achieved from renewable energy projects that are repowered or retrofitted to improve the overall efficiency of the facility would qualify as a new resource under this section.
  (4) **Affiliated purchases.** Any renewable resources obtained from an affiliate of the regulated utility must be secured through an arm's-length, competitive solicitation.

(e) **Renewable energy tariff requirements.** All electric utilities choosing to offer a renewable resource tariff under this section shall submit for commission review and approval a tariff that implements the provisions of this section. No utility may conduct any sales or marketing activities under a renewable energy program until a renewable energy tariff has been filed and approved by the commission. Each tariff submitted shall, at a minimum, contain the following provisions:
  (1) **Definitions.** This section shall define all relevant terms and concepts in a manner that is simple and easy to understand.
  (2) **Rates and charges.** This section shall clearly identify the charges that the participants will incur for participating at various levels in the program. The tariff shall allow participation at a variety of monthly costs or energy demand volume levels and will clearly state how much renewable energy a

given monthly charge will buy, or alternatively, the cost to buy a given number of kWh from a renewable resource.

(f) **Tariff attributes and operation.** A renewable energy tariff enables a utility's customers to receive all or part of their energy needs from renewable energy resources. All tariffs filed shall contain the following attributes:

(1) All retail customers shall be given the opportunity to purchase all or a portion of their energy requirements under this tariff.

(2) The renewable energy price must be cost-based. The relationship between the renewable energy price and the cost of the acquired resource must be demonstrated in the utility's initial tariff-filing package. The tariff must identify with specificity the elements of the price, including the portion of the price that is attributable to the cost of the renewable energy, and the utility's profit, if any. The filing shall identify the utility's projections of renewable energy demand in kWh and renewable marketing and advertising costs that underlie the per kWh marketing and advertising cost included in the total renewable energy price, and show that it meets the limits identified in subsection (l)(1) of this section.

(3) No utility may sell existing renewable energy under a tariff pursuant to this section until it has made a commitment to acquire renewable energy from new resources. These new resources shall be deployed within 24 months of tariff approval.

(4) A utility may not charge customers for any more kWh of renewable energy provided under this tariff than it has specifically received to serve customers under this tariff.

(g) **Marketing.**

(1) **Marketing plan.** Each utility shall include a description of its marketing plan with its initial tariff filing package. Included in this description shall be an explanation of how the utility intends to provide customers with clear information regarding how they may obtain the service(s).

(2) **Disclosure of resource location.** Each utility shall disclose the location of the renewable resource offered under the tariff on all advertising, educational, or promotional materials in a bold and conspicuous manner.

(h) **Accountability.** Each utility shall provide a report to renewable energy tariff subscribers on the status of the program and use of funds. This report shall contain information that will allow customers to review the benefits they have received as a result of the costs they have voluntarily incurred to buy renewable energy under the tariff.

(1) **Contents.** The report required by this section shall be organized to clearly convey the following information to tariff subscribers and other interested customers:

(A) The number of program participants.

(B) The total revenues collected through the renewable energy tariff, total expenditures under the tariff, and how renewable energy tariff revenues were spent for the calendar year.

(C) The amount of renewable energy sold to subscribers under the tariff and the amount of new renewable resources acquired.

(D) The unit cost of the new renewable resource acquisition (by renewable technology if appropriate), and how it compares to benchmark prices for the utility's current resource mix and to new non-renewable resources.

(E) The location, technology, and providers of new and existing renewable energy provided to customers under the tariff.

(F) The amount of generation-related air emissions that have been avoided as a result of the program.

(G) Information regarding any local demonstration or education projects (e.g., school photovoltaic installations) to support either the renewable energy tariff or the education program.

(2) Information shall be provided to renewable energy tariff subscribers annually and shall be filed with the commission and the Texas Natural Resource Conservation Commission on the same date the information is provided to subscribers.

(i) **Tariff approval process.** The commission will review and approve or deny each utility's tariff filed under this section within 90 days of filing. It will consider the following matters in its review:

(1) **Cost analysis.** Each utility shall file supporting analysis showing that the proposed cost of renewable energy is reasonable and meets the requirements of subsection (f)(2) of this section.

(2) **Program marketing and administrative costs analysis.** Each utility shall develop a marketing plan for its renewable energy tariff that explains how the utility will publicize, market, and advertise the tariff. The plan shall include the schedule of renewable energy prices, and itemized costs to execute the marketing plan. Disclosure of this material may be subject to a protective order if the commission determines it involves confidential competitive business information.

(3) **Relevant assumptions.** Each utility shall explain all relevant assumptions, including the cost of non-renewable electric resources.

(4) **Resource procurement plan**. The utility shall explain how it intends to secure the renewable energy needed to meet its projected customer demand for the first two years the tariff is in effect; disclosure of this material may be protected if the commission determines it involves confidential competitive business information.

(j) **Education program.** Each utility that offers a renewable energy tariff shall also design and implement a customer education program about renewable energy. The utility shall provide educational materials to all of its customers on renewable resources as supply-side options and as demand-side options. Each utility shall inform its customers of the utility's generation mix and generation emissions. This information shall be comprehensible and succinct. Customer educational materials shall be sent to customers during the initial tariff offering in conjunction with the initial renewable energy marketing materials, and shall be distributed at least annually.

(k) **Criteria for educational materials.**

(1) Educational materials may include the utility's name and the name of the utility's commission-approved program with information on how to participate, but shall otherwise not be used to promote the utility or any of its other service offerings in any way.

(2) Educational materials should include information on renewable energy technology applications as defined in §25.5 of this title, as well as information regarding the potential for renewable energy technology development in the State of Texas. It should include information on renewable resources both for supply- and demand-side applications, including off-grid and peak-shaving uses.

(3) The utility's generation mix shall be disclosed to all customers in table form as a component of the tariff's educational campaign. Disclosure statements shall indicate the utility's generation mix in percentages rounded to the nearest whole number for the previous calendar year using the following categories: coal and lignite, natural gas, nuclear fuel, renewable resource, and fuel oil and other.

(4) The utility's generation emissions, as well as nuclear waste, shall be disclosed in total and shall include emissions associated with the utility's power purchases to the extent that this information is available. Disclosure statements shall indicate the utility's average monthly generation emissions or average nuclear waste per customer for each customer class and by MWh generated for the previous calendar year, based on the average emissions or nuclear waste by fuel type, for: nitrogen oxide (NO_x), sulfur dioxide (SO_2), carbon dioxide (CO_2), particulate matter, and nuclear waste.

(5) Each utility shall file these materials with the commission as part of its tariff-filing package for approval.

(l) **Cost recovery.** Utilities shall be allowed to recover costs incurred through the tariff in the following manner:

(1) **Marketing and administration costs.** Program marketing and administration costs may be included within the premium for renewable energy, and shall not exceed 20% of the total revenues collected from the renewable energy price in the first two years that the tariff is in effect and 10% in subsequent years. Prudently incurred marketing and administration costs in excess of these limits may be recoverable through base rates pursuant to §23.21 (c)(1)(E) of this title (relating to Cost of Service).

(2) **Education program costs.** All prudently incurred costs of commission approved customer education materials and activities shall be recoverable and allocated among all customers through base rates.

(m) **Commission review.** The commission will periodically review each utility's renewable energy tariff and activities to ensure that new renewable energy resources are deployed in/or next to the State of Texas and that program participants are receiving appropriate benefits from participation.

§25.261. Stranded Cost Recovery of Environmental Cleanup Costs.

(a) **Purpose.** The purpose of this section is to:

(1) establish the procedures and criteria for determining the amount of stranded cost recovery electric utilities and affiliated power generation companies shall receive for environmental cleanup costs incurred to improve air quality in the state pursuant to Public Utility Regulatory Act (PURA) §39.263; and

(2) minimize stranded costs associated with the implementation of PURA §39.264.

(b) **Applicability.** This section applies to:

(1) electric utilities that seek to recover capital costs incurred during the period January 1, 1999 to April 30, 2003 to improve air quality; and

(2) affiliated power generation companies that seek to recover capital costs incurred during the period January 1, 2002, to April 30, 2003 to improve air quality.

(c) **Definitions.** The following words and terms, when used in this chapter, shall have the following meanings unless the context clearly indicates otherwise:

(1) **Conservation Commission —** The Texas Natural Resource Conservation Commission.

(2) **Cost of replacement generating capacity —** The cost of replacing generating capacity lost through retirement of an electric generating facility. The annual cost of replacement generating capacity will be calculated using the following equation:

RGC=(PP)(G)	
Where:	
RGC =	Annual cost (in dollars) of replacement generating capacity
PP =	Purchased power price determined using commission-approved price projections.
G =	Amount of generation (megawatt-hour), which is the annual average of the output of the applicable electric generating facility for the three most current years as reported on Form EIA-767 or if not available on Form EIA-767, then the average annual output as reported to the commission, declining for the years 2004 and thereafter at the rate of 2.0% per year.

(3) **Electric generating facility** — A facility that generates electric energy for compensation and that is owned or operated by a person in this state, including a municipal corporation, electric cooperative, or river authority.

(4) **Expected remaining life** — The estimated life in whole years of the generating facility from May 1, 2003 as estimated by the utility at the time of filing its application for approval of its cost-effectiveness determination plan.

(5) **Net book value** — The original cost of an asset less accumulated depreciation.

(6) **Offset —** The allocation of emission allowances or credits from one facility to another facility in the same region.

(7) **Operations and maintenance (O&M) escalator** — The applicable operations and maintenance (O&M) escalator set forth in the unbundling cost of service rate filing package. The O&M escalator

for a gas-fired electric generating unit shall be 2.0% and the O&M escalator for a coal-fired electric generating unit shall be 1.0%. Notwithstanding the foregoing, the O&M escalator for TNP One shall be 1.5%.

(8) **Region** — The East Texas Region, West Texas Region, or El Paso Region, as defined by the conservation commission at 30 TAC §101.330.

(9) **Retirement** — The permanent removal from service of an electric generating facility.

(10) **Retrofit** — The installation of control technology on an electric generating facility to reduce the emissions of nitrogen oxide, sulfur dioxide, or both.

(11) **Retrofit Cost —** The net present value of the total capital cost and operating and maintenance cost to operate an electric generating facility after installation of a retrofit. The cost of a retrofitted unit shall be expressed in net present value dollars as of 2003 using the equation VALUE = (ECCR + O&M + FUEL + O&MR + OE), where:

(A) VALUE = net present value in 2003 over the expected remaining life of a retrofitted unit;

(B) ECCR = net present value of the estimated capital cost of retrofit as of 2003 and the net present value as of 2003 of the expected capital cost of environmental controls installed no later than 2010 to meet future regulations for emissions. The commission will adopt a methodology for calculating the capital cost of environmental controls to meet future regulations for emissions.

(C) O&M = net present value as of 2003 of operation and maintenance cost of unit without retrofit, calculated as O&M = (((average of plant non-fuel fixed O&M cost reported for the most current five calendar years on FERC Form 1) x ((maximum generator nameplate rating as reported for the unit on Form EIA-411 or if not available on Form EIA-411, then the rating as reported to the commission) / (sum of the maximum generator nameplate rating as reported for all units comprising the plant at which such unit is located on Form EIA-411 or if not available on Form EIA-411, then the rating as reported to the commission))) + ((average of plant non-fuel variable O&M cost, expressed in $/MWh, reported for the most current five calendar years on FERC Form 1) x (unit generation for 2003, calculated as the average generation in MWh for the most current five years as reported on Form EIA-767 or if not available on Form EIA-767, then the generation as reported to the commission, declining for the years 2004 and thereafter at the rate of 2.0% per year)) escalated by the O&M Escalator for each year subsequent to the year in which the cost effectiveness determination was filed;

(D) FUEL = Cost of fuel, calculated as net present value as of 2003, over the expected remaining life of the retrofitted unit, using the equation FUEL = HR x G x Gas where:

(i) HR = unit heat rate, calculated as the average of the heat rate reported for the most current five calendar years on Form EIA-411 or if not available on Form EIA-411, then the heat rate as reported to the commission, expressed in mmBtu/MWh;

(ii) G = unit generation, calculated for 2003 as the average generation in MWh reported for the three most current calendar years on Form EIA-767 or if not available on Form EIA-767, then the generation as reported to the commission, declining for the years 2004 and thereafter at the rate of 2.0% per year; and

(iii) Gas = forward natural gas prices as adopted for the ECOM model in August, 2000 by the commission;

(E) O&MR = Net present value as of 2003 of estimated additional operating and maintenance cost resulting from the retrofit, beginning with costs for calendar year 2003 and escalated each year at 2.0% per year and the net present value as of 2003 of the expected operating and maintenance cost of environmental controls to meet future regulations for emissions beginning with costs for the estimated year of installation and escalated each year through 2010 at 2.0% per year. The commission will adopt a methodology for calculating the O&MR cost of environmental controls to meet future regulations for emissions;

(F) OE = Ownership effect, calculated as the net present value as of 2003, over the expected remaining life of the retrofitted unit, using the equation OE = VALUE(PT + PI + CAPIMP – OMTA – CAPIMPDEP – DEPTAXBEN) where:
   (i) PT = annual property tax, adjusted for income tax benefit = (applicable property tax rate) x (ADJECCR) x (1 – income tax rate) where ADJECCR is equal to ECCR reduced to reflect any property tax exemption for which the unit might qualify;
   (ii) PI = annual property insurance, adjusted for income tax benefit = (applicable property insurance rate) x (ECCR) x (1 – income tax rate);
   (iii) CAPIMP = annual continuing capital improvements, adjusted for income tax benefit = (1.25% of the sum of the net book value plus improvements) x (1- income tax rate);
   (iv) OMTA = annual income tax benefit on O&MR= (income tax rate) x (estimated additional operating and maintenance cost of the retrofit for the applicable year);
   (v) CAPIMPDEP = annual tax depreciation on CAPIMP; and
   (vi) DEPTAXBEN = (income tax rate) x (annual tax depreciation on ECCR).

(12) **Transportation equipment** — A rail spur at a lignite-fired electric generating facility installed to receive deliveries of western coal. Transportation equipment does not include rail cars and unloading facilities.

(d) **Requirements.**

(1) **Qualifying retrofit costs.** To be eligible for recovery as invested capital pursuant to PURA §39.263, a retrofit cost must be:
   (A) reasonable and prudent;
   (B) incurred in carrying out the most cost-effective alternative for improving air quality as approved pursuant to this section;
   (C) incurred to reduce or offset emissions by an amount and at a location that is consistent with the air quality goals and policies of the conservation commission;
   (D) incurred to offset or reduce the emission of airborne contaminants from an electric generating facility, where:
      (i) the emission reduction or offset is determined by the conservation commission to be an essential component in achieving compliance with a national ambient air quality standard. For purposes of this section, any emission reduction or offset achieved by an electric utility or affiliated power generation company to comply with conservation commission regulations at 30 TAC Chapter 117 is deemed to have been determined by the conservation commission to be an essential component in achieving compliance with a national ambient air quality standard; or
      (ii) the reduction or offset is necessary for an unpermitted electric generating facility to obtain a permit in the manner provided by PURA §39.264; and
   (E) associated with the engineering, procurement, or installation of pollution control equipment or transportation equipment, or the purchase of emissions allowances.

(2) **Qualifying retirement costs.** Retirement costs may be included in the electric generating facility's stranded cost determination if retirement of the facility is the most cost-effective alternative, taking into account the cost of replacement generating capacity. Recoverable retirement costs are the net book value of the facility, including retirement costs, less salvage value.

(3) **When costs incurred.** For purposes of this section, the electric utility or affiliated power generation company has incurred costs if it has expended funds or has committed to expend funds under the terms of a written agreement.

(4) **Operating and maintenance costs.** This section does not authorize the recovery of operating and maintenance costs or the capital cost of a new electric generating facility.

(5) **Apportionment of reductions.** As provided in this paragraph, the commission may apportion the capital invested to reduce emissions of nitrogen oxides, sulfur dioxide, or both, among one or more entities owning facilities located in the same region. The capital investments for which recovery is sought must have been incurred pursuant to a written agreement between the entities executed prior to the date any such costs were incurred. The commission may not apportion capital costs under this provision unless the criteria of paragraph (1) of this subsection are met for each electric generating facility seeking capital cost recovery. Capital costs shall be apportioned by prorating the total capital invested between entities on the basis of reductions of nitrogen oxides, sulfur dioxide, or both, realized at each participating entity's facilities in the region.

(e) **Request for approval of cost-effectiveness determination.**

(1) **Application.** On or before January 10, 2003, an electric utility or affiliated power generation company that seeks recovery of capital costs pursuant to this section shall file an application for a determination that its plan for meeting the requirements of PURA §39.264 and the regulatory programs designed to achieve compliance with national ambient air quality standards are cost-effective under this section. No more than one application may be filed for generating facilities owned by the same electric utility or affiliated power generation company in the same region. The application shall include the information specified in subparagraphs (A) – (H) of this paragraph.

(A) Description. A general description of the generating facility, including but not limited to:

(i) net generating capacity in megawatts;

(ii) type of fuel used for electric generation;

(iii) the county and region in which each facility addressed in the application is located;

(iv) average capacity factor for the three most current calendar years as reported to the commission;

(v) generation in megawatt-hours for the three most current calendar years, as reported on Form EIA-767 or if not available on Form EIA-767, then as reported to the Public Utility Commission of Texas;

(vi) the expected remaining life of the facility; and

(vii) any other information required to perform the analysis prescribed by this section.

(B) Total emissions. The total annual emissions (in tons) of nitrogen oxides and sulfur dioxide:

(i) for the year 1997;

(ii) for the most recent calendar year for which data is available;

(iii) that is expected for the first calendar year after the implementation of the air quality improvement strategies for which cost recovery will be requested; and

(iv) for the calendar years 2003 through 2005.

(C) Allocated emissions allowances. The number of emission allowances allocated to the electric generating facility by the conservation commission.

(D) Capital cost estimate. The total amount of qualifying capital costs for each option evaluated by the electric utility or affiliated power generation company.

(E) Alternatives. A decision analysis for all electric generating facilities owned by a utility or affiliated power generation company in the same region comparing the cost-effectiveness of the retirement option with retrofit options and all other possible options considered by the electric utility or affiliated power company. Other options shall include:

(i) offsetting emissions at the electric generating facility by installing control technology at another facility, consistent with the rules of the conservation commission; and

(ii) switching fuel used for electricity generation at the electric generating facility.

(F) Comparative cost analysis. The net present value of the capital, operating, and maintenance costs of each option considered pursuant to subparagraph (E) of this paragraph. The period of the analysis shall begin on May 1, 2003, and extend for a period of 15 years. The discount rate used in the analysis and the cost of capital associated with each option shall be calculated differently. Both shall start with the capital structure and cost of capital as they are reported for the end of 1999 in the utility's annual report made pursuant to PURA §39.257. The discount rate shall be the after-tax weighted cost of capital, while the cost of capital associated with each option shall be taken directly from the annual report, except for the cost of debt. The cost of debt for this purpose shall be the average cost of debt for the months of October, November, and December 1999 as reported by Moody's Investors Service for utilities with the same Moody's bond rating as the utility making the filing adjusted to reflect any tax-exemption benefits for which a particular option might qualify. All assumptions used in the analysis shall be provided. If the lowest-cost alternative is not selected as the most cost-effective, an explanation of why it was not selected shall be provided. Where an electric generating facility is required to remain active to ensure reliability, retrofit shall be deemed to be the most cost-effective alternative for that facility. The commission shall give great weight to the recommendation of the Electric Reliability Council of Texas (ERCOT) Independent System Operator (ISO) in determining whether a facility is needed for reliability purposes.

(G) Retrofit. The retrofit alternative analysis shall include calculation of retrofit cost and an estimate of the total cost per ton of pollutant reduced for each option considered. The retrofit alternative analysis shall also include the time-discounted, probability–adjusted cost of environmental retrofits that are reasonably foreseeable to require air quality improvement compliance no later than 2010. If the expected remaining life of the generating facility is less than 15 years, the retrofit analysis shall include the net present value of all relevant costs of retirement for those years remaining after the retirement date.

(H) Retirement. The retirement analysis shall include the net present value of all relevant costs of retirement for each electric generating facility, including:

(i) the cost of replacement generating capacity in dollars as defined in subsection (c)(2) of this section. The amount of replacement generating capacity shall be the generating capacity of the unit retired adjusted, when appropriate and depending upon the size of the unit, to reflect energy savings or additions attributable to energy efficiency, transmission upgrades, distributed generation, and other similar measures; and

(ii) the net book value of the facility, including retirement costs and offsetting salvage value, which includes but is not limited to the market value of the land after the facility is retired, and the value of water rights, pollution credits or benefits associated with the facility, and other infrastructure.

(2) **Notice.** Notice of an application for approval of a cost-effectiveness determination shall be provided through newspaper publication once a week for two consecutive weeks in a newspaper of general circulation throughout the service area of each electric generating facility addressed in the application. Such newspaper notice shall state in plain language:

(A) the purpose of the application;

(B) the electric generating facilities addressed in the application;

(C) the air quality improvement strategy proposed for each electric generating facility addressed in the application; and

(D) the date the application will be deemed approved if no objection is filed with the commission.

(3) **Approval of an application for determination of cost-effectiveness.** An application shall be deemed approved without further commission action if no objection to the application is filed with the commission within 60 days after the application was filed and adequate notice has been completed.

(4) **Decision.** If an application for approval of an emissions reduction plan is not approved under paragraph (3) of this subsection, the commission shall render a decision approving or denying the

application within 180 days from the date of filing of a complete application unless good cause is shown for extending the 180-day period.

(f) **Reconciliation of environmental cleanup costs during the true-up proceedings.** The commission's final determination of recoverable environmental cleanup costs under PURA §39.263 shall be made during the true-up proceedings under PURA §39.262, subject to the provisions of this paragraph:

(1) **Burden of proof for recovery of costs.**

(A) Burden of proof. In determining the amount of environmental cleanup costs that the electric utility may recover as invested capital under PURA §39.263, the electric utility or affiliated power generation company has the burden of showing that its qualifying costs during the period were prudent, reasonable, and necessary and were incurred to implement the most cost-effective alternative.

(B) Benchmarks. For those electric generating facilities where their owners can show that retrofitting the facilities is more cost effective than retiring them, the commission presumes that costs for retrofitting a natural gas-fired electric generating facility that are no more than $7.00 per kilowatt for nitrogen oxide combustion control technology and $25 per kilowatt for technology that reduces nitrogen oxide emissions by 80% or more are reasonable and prudent. Likewise, the commission presumes that costs for retrofitting a coal-fired electric generating facility that are no more than $10 per kilowatt for nitrogen oxide combustion control technology and $50 per kilowatt for technology that reduces nitrogen oxide emissions by 80% or more are reasonable and prudent. For actual costs that exceed these per-kilowatt benchmarks, the utility must establish that those costs were reasonably incurred. Costs that the utility estimates and the commission affirms as the estimated costs of each plant's environmental retrofit, as determined in a proceeding under subsection (e) of this section, shall be aggregated as the maximum reasonable and prudent investment for the fleet retrofit, and the costs in excess of the fleet total are not recoverable through stranded costs.

(2) **Scope.** Any issue related to determining the prudence and reasonableness of the environmental clean-up costs which the electric utility or affiliated power generation company is seeking recovery as invested capital shall be within the scope of the proceeding. The prudence and reasonableness of the alternative selected for each electric generating facility is not within the scope of this proceeding.

§25.263. True-up Proceeding.

(a) **Purpose.**

(1) The purpose of the true-up proceeding is to quantify and reconcile the amount of stranded costs, the differences in the price of power obtained through the capacity auctions and the power costs used in the excess costs over market (ECOM) model; the results of the annual reports; the level of excess revenues, net of nonbypassable delivery charges, from customers who continue to pay the price to beat (PTB); the reasonable regulatory assets not previously approved in a rate order that are being recovered through competition transition charges (CTCs) or transition charges (TCs); and the final fuel balances. The purpose of the true-up proceeding is also to provide for the recovery of regulatory assets not already approved for securitization that were to be considered in future proceedings pursuant to a commission financing order in a securitization case.

(2) An electric utility, together with its affiliated retail electric provider (AREP), its affiliated power generation company (APGC), and its affiliated transmission and distribution utility (TDU), shall not be permitted to over-recover stranded costs through the application of the measures provided in the Public Utility Regulatory Act (PURA), Chapter 39, or under the procedures established in PURA §39.262 and this section.

(b) **Application.** This section applies to all investor-owned transmission and distribution utilities established pursuant to PURA §39.051, their APGCs, and their AREPs. In addition, the reporting requirements of subsection (j)(6) of this section apply to all retail electric providers (REPs) serving residential and small commercial customers.

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

(1) **Capacity auction total price of power ($/MWh)** — The total (fuel plus non-fuel) capacity auction revenues for entitlements to capacity for the years 2002 and 2003 divided by the total capacity auction energy (expressed in MWh) scheduled to be delivered for those entitlements over the same time period.

(2) **Independent third party** — The party designated by the commission to perform the duties described in subsection (j) of this section.

(3) **Mitigation** — The total excess earnings and redirected depreciation applied to generation assets pursuant to PURA §39.254 and §39.256 or a commission order issued after 1996 that approved a utility's transition case.

(4) **Net mitigation** — Any mitigation that has not been reversed or refunded as of the date of the final order in the true-up proceeding.

(5) **Net value realized** — All compensation paid by a buyer for generation assets, including the buyer's assumption of debt, less any costs of sale such as legal fees, broker fees, and other reasonable transaction costs.

(6) **Projected stranded costs** — The value produced by the ECOM model and approved by the commission in the proceeding conducted pursuant to PURA §39.201.

(7) **Regulatory assets** — The generation-related portion of the Texas jurisdictional portion of the amount reported by the electric utility in its 1998 annual report on Securities and Exchange Commission Form 10-K as regulatory assets and liabilities, offset by the applicable portion of generation-related investment tax credits permitted under the Internal Revenue Code of 1986.

(8) **Residential market price of electricity** — The volume-weighted average price, less average nonbypassable charges (each expressed in cents per kilowatt-hour (kWh)), calculated by the independent third party for residential electric service provided by non-affiliated retail electric

providers and non-provider of last resort (POLR) service providers competing in the TDU region. The price determined by the independent third party shall be based upon pricing disclosures pursuant to §25.475(e) of this title (relating to Information Disclosures to Residential and Small Commercial Customers) and other information provided to the independent third party.

(9) **Residential net price to beat —** The average residential PTB rate (expressed in cents per kWh) less the average nonbypassable charges (expressed in cents per kWh) applicable to residential customers.

(10) **Small commercial market price of electricity** — The volume-weighted average price, less average nonbypassable charges (each expressed in cents per kWh), calculated by the independent third party for small commercial electric service provided by non-AREPs and non-POLR service providers competing in the TDU region. The price determined by the independent third party shall be based upon pricing disclosures pursuant to §25.475(e) of this title and other information provided to the independent third party.

(11) **Small commercial net price to beat —** The average small commercial PTB rate (expressed in cents per kWh) less the average nonbypassable charges (expressed in cents per kWh) applicable to small commercial customers.

(12) **Transferee corporation** — A separate affiliated or non-affiliated company to whom an electric utility or its APGC transfers generation assets.

(13) **Transmission and distribution utility (TDU)** — A transmission and distribution utility that, pursuant to PURA §39.051, is the successor in interest of an electric utility certificated to serve an area.

(14) **Transmission and distribution utility region (TDU region) —** The affiliated transmission and distribution utility's service territory.

(d) **Obligation to file a true-up proceeding.**

(1) Each TDU, its APGC, and its AREP shall jointly file a true-up application pursuant to subsection (e) of this section.

(2) Each TDU that is a successor in interest of any utility that was reported by the commission to have positive ECOM, denoted as the "base case" for the amount of stranded costs before full retail competition in 2002 with respect to its Texas jurisdiction in the April 1998 Report to the Texas Senate Interim Committee on Electric Utility Restructuring entitled "Potentially Strandable Investment (ECOM) Report: 1998 Update," and such TDU's, APGC's, and AREP's, shall file the true-up application as required by subsections (f) – (k) of this section.

(3) All TDUs not described in paragraph (2) of this subsection, their APGCs, and their AREPs shall file the applications required by subsections (h) and (j) of this section.

(e) **True-up filing procedures.**

(1) Each TDU, APGC, and AREP shall file all testimony and schedules on which they intend to rely for their direct case in accordance with the true-up filing package prescribed by the commission.

(A) Within 20 calendar days of the filing of a true-up application, commission staff or any intervenor may file a motion stating that the filing is materially deficient. Any such motion shall include a detailed explanation of the claimed material deficiencies.

(B) If the presiding officer determines that an application is materially deficient, the TDU, APGC, and AREP shall correct the deficiencies within 30 calendar days. The deadline for final commission order shall be extended day for day from the date of initial filing until the corrections are filed with the commission.

(2) At least 90 days prior to the filing of the first true-up application scheduled by the commission, a utility's APGC shall file a notification of intent with the commission if it intends to utilize PURA §39.262(i) to determine the amount of its stranded costs for nuclear assets.

(3) The commission may initiate a generic proceeding to determine true-up issues that are common to multiple TDUs, APGCs, and AREPs. This proceeding may include updates to the ECOM model required by subsection (f)(2)(B) of this section, in the event a notification of intent is filed pursuant to paragraph (2) of this subsection. The commission may order further updates to any order approved in a generic proceeding pursuant to this section for any utility whose customers are not offered competition on January 1, 2002.

(4) As part of the true-up proceeding, the commission shall make a determination with respect to whether the TDU, the APGC, and the AREP have complied with PURA §39.252(d). If the commission finds that the TDU, the APGC, or the AREP have failed, individually or in combination, to fully comply with their obligations under PURA §39.252(d), the commission may reduce the net book value of the APGC's generation assets or take other measures it deems appropriate in the true-up proceeding filed under this section. In making a determination as to compliance with PURA §39.252(d), the commission shall not substitute its judgment for a market valuation of generation assets determined under PURA §39.262(h) or (i).

(5) The State Office of Administrative Hearings shall employ expedited procedures during discovery in the true-up proceedings.

(6) The commission shall issue the final order for each proceeding filed under this section not later than the 150th day after the filing of a complete, non-deficient application. Notwithstanding the foregoing, however, the 150-day deadline may be extended by the commission for good cause.

(f) **Quantification of market value of generation assets.**

(1) Market value of generation assets shall be quantified using one or more of the following methods:

(A) **Sale of assets method.** If an electric utility or its APGC sells some or all of its generation assets after December 31, 1999, in a bona fide third-party transaction under a competitive offering, the total net value realized from the sale shall establish the market value of the generation assets sold. Within 30 days of closing, the utility or its APGC shall provide to the commission a detailed explanation, which may be filed confidentially, of the transaction and a description of the generating unit, property boundaries, fuel and parts, emission allowances, and other general categories of items associated with the sale, including any ancillary items related to the assets.

(B) **Stock valuation method.** The following method of market valuation without using a control premium may be used to value generation assets.

(i) If, at any time after December 31, 1999, an electric utility or its APGC has transferred some or all of its generation assets, including, at the election of the electric utility or the APGC, any fuel and fuel transportation contracts related to those assets, to one or more separate affiliated or nonaffiliated corporations, not less than 51% of the common stock of each corporation is spun off and sold to public investors through a national stock exchange, and the common stock has been traded for not less than one year, the resulting average daily closing price of the common stock over 30 consecutive trading days chosen by the commission out of the last 120 consecutive trading days before the true-up filing required by this section establishes the market value of the common stock equity in each transferee corporation.

(ii) The average book value of each transferee corporation's debt and preferred stock securities during the 30-day period chosen by the commission to determine the market value of common stock shall be added to the market value of its stock.

(iii) The market value of each transferee corporation's assets that is determined as the sum of clauses (i) and (ii) of this subparagraph shall be reduced by the corresponding net book value of the assets acquired by the transferee corporation from any entity other than the affiliated electric utility or APGC.

(iv) The market value of the assets determined from the procedures required by clauses (i), (ii), and (iii) of this subparagraph establishes the market value of the generation assets transferred by the affiliated electric utility or APGC to each separate corporation

(C) **Partial stock valuation method.** The following method of market valuation using a control premium may be used to value generation assets.

(i) If, at any time after December 31, 1999, an electric utility or its APGC has transferred some or all of its generation assets, including, at the election of the electric utility or the APGC, any fuel and fuel transportation contracts related to those assets, to one or more separate affiliated or nonaffiliated corporations, at least 19%, but less than 51%, of the common stock of each corporation is spun off and sold to public investors through a national stock exchange, and the common stock has been traded for not less than one year, the resulting average daily closing price of the common stock over 30 consecutive trading days chosen by the commission out of the last 120 consecutive trading days before the filing establishes the market value of the common stock equity in each transferee corporation.

(ii) The commission may accept the market valuation to conclusively establish the value of the common stock equity in each transferee corporation or convene a valuation panel of three independent financial experts to determine whether the per-share value of the common stock sold is fairly representative of the per-share value of the total common stock equity or whether a control premium exists for the retained interest.

(iii) Should the commission elect to convene a valuation panel, the panel must consist of financial experts chosen from proposals submitted in response to commission requests from the top ten nationally recognized investment banks with demonstrated experience in the United States electric industry, as indicated by the dollar amount of public offerings of long-term debt and equity of United States investor-owned electric companies over the immediately preceding three years as ranked by the publication "Securities Data" or "Institutional Investor."

(iv) If the panel determines that a control premium exists for the retained interest, the panel shall determine the amount of the control premium, and the commission shall adopt the determination, but may not use the control premium to increase the value of the assets by more than 10%.

(v) The costs and expenses of the panel, as approved by the commission, shall be paid by each transferee corporation.

(vi) The determination of the commission, based on the finding of the panel and other admitted evidence, conclusively establishes the value of the common stock of each transferee corporation.

(vii) The average book value of each transferee corporation's debt and preferred stock securities during the 30-day period chosen by the commission to determine the market value of common stock shall be added to the market value of its stock.

(viii) The market value of each transferee corporation's assets shall be reduced by the corresponding net book value of the assets acquired by the transferee corporation from any entity other than the electric utility or its APGC.

(ix) The market value of the assets resulting from the procedures required by clauses (i) - (viii) of this subparagraph establishes the market value of the generation assets transferred by the electric utility or APGC to each transferee corporation.

(D) **Exchange of assets method.** If, at any time after December 31, 1999, an electric utility or its APGC transfers some or all of its generation assets, including any fuel and fuel transportation contracts related to those assets, in a bona fide third-party exchange transaction, the stranded costs related to the transferred assets shall be the difference between the net book value and the market value of the transferred assets at the time of the exchange, taking into account any other consideration received or given.

(i) The market value of the transferred assets may be determined through an appraisal by a nationally recognized independent appraisal firm, if the market value is subject to a market valuation by means of an offer of sale in accordance with this subparagraph.

(ii) To obtain a market valuation by means of an offer of sale, the owner of the asset shall offer it for sale to other parties under procedures that provide broad public notice of the offer and a reasonable opportunity for other parties to bid on the asset. The owner of the asset shall provide to the commission copies of all documentation explaining and attesting to the utility's sale proposal.

(iii) The owner of the asset may establish a reserve price for any offer based on the sum of the appraised value of the asset and the tax impact of selling the asset, as determined by the commission.

(iv) Within 30 days of closing, the utility or its APGC shall provide to the commission a detailed explanation, which may be filed confidentially, of the transaction and a description of the generating unit, property boundaries, fuel and parts, emission allowances, and other general categories of items associated with the transfer, including any ancillary items related to the assets.

(2) **ECOM Method.** Unless an electric utility or its APGC combines all its remaining generation assets into one or more transferee corporations pursuant to paragraph (1)(B) or (C) of this subsection, the electric utility shall quantify its stranded costs for nuclear assets using the ECOM method.

(A) The ECOM method is the estimation model prepared for and described by the commission's April 1998 Report to the Texas Senate Interim Committee on Electric Restructuring entitled "Potentially Strandable Investment (ECOM) Report: 1998 Update." The methodology used in the model must be the same as that used in the 1998 report to determine the "base case."

(B) As part of the filing specified in subsection (d) of this section, the electric utility shall rerun the ECOM model using updated company specific inputs required by the model, updating the market price of electricity, and using updated natural gas price forecasts and the capacity cost based on the long-run marginal cost of the most economic new generation technology then available, as approved by the commission pursuant to subsection (e)(3) of this section. Natural gas price projections used in the model shall be forward prices of Houston Ship Channel natural gas.

(C) Growth rates in generating plant operations and maintenance costs and allocated administrative and general costs shall be benchmarked by comparing those costs to the best available information on cost trends for comparable generating plants.

(D) Capital additions shall be benchmarked using the 1.5% limitation set forth in PURA §39.259(b).

(g) **Quantification of net book value of generation assets.**

(1) For purposes of this section, the net book value of generation assets shall be established as of December 31, 2001, or the date a market value is established through a market valuation method under subsection (f) of this section, whichever is earlier.

(2) Net book value of generation assets consists of:

(A) The generation-related electric plant in service, less accumulated depreciation (exclusive of depreciation related to mitigation), plus generation-related construction work in progress, plant held for future use, and nuclear, coal, and lignite fuel inventories, reduced by:

(i) net mitigation;

(ii) the net book value of nuclear generation assets if quantification of ECOM related to those nuclear generation assets is determined pursuant to PURA §39.262(i); and

(iii) any generation-related invested capital recoverable through a CTC, exclusive of related carrying costs, projected to be collected through the date of the final order in the true-up proceeding.

(B) Above-market purchased power costs arising from contracts in effect before January 1, 1999, including any amendments and revisions to such contracts resulting from litigation initiated before January 1, 1999.

(i) The purchased power market value of the demand and energy included in the purchased power contracts shall be determined by using the weighted average costs of the highest three offers from a bona fide third-party transaction or transactions on the open market.

(ii) The bona fide third-party transaction or transactions on the open market shall be structured so that the above-market purchased power costs are determined pursuant to subclause (I) or (II) of this clause.

(I) A transaction may be structured so the electric utility pays a third party to assume the utility's obligations under the purchased power contract. The weighted average of the three highest offers received in the transaction establishes the above-market purchased power costs.

(II) A transaction may be structured so a third party pays the utility to take power under the purchased power contract. The difference between the net present value of obligations under the existing contracts at the utility's cost of capital and the weighted average of the three highest offers received in the transaction establishes the above-market purchased power costs.

(C) Deferred debits, to the extent they have not been securitized, related to a utility's discontinuance of the application of SFAS No. 71 ("Accounting for the Effects of Certain Types of Regulation") for generation-related assets if required by PURA Chapter 39.

(D) Capital costs incurred before May 1, 2003 to improve air quality to the extent they have been approved by the commission pursuant to §25.261 of this title (relating to Stranded Cost Recovery of Environmental Cleanup Costs).

(E) Any adjustments resulting from the commission's review of the TDU's, APGC's, and AREP's efforts pursuant to subsection (e)(4) of this section.

(h) **True-up of final fuel balance.**

(1) An APGC shall reconcile the former electric utility's final fuel balance determined under PURA §39.202(c).

(2) The final fuel balance shall be reduced by any revenues collected by the AREP under any commission-approved fuel surcharge, from the date of introduction of competition to the utility's

customers through the date of the true-up filing under this section, so long as the fuel surcharge is associated with fuel costs incurred during the time period covered by the final reconcilable fuel balance.

(3) If an electric utility or its TDU or APGC is assessed by another utility in Texas a fuel surcharge after 2001 for under-recoveries occurring through the end of 2001, the surcharged utility shall add the amount of surcharges and any associated carrying costs paid after 2001 to its final fuel balance.

(4) The final fuel balance, as adjusted by paragraphs (2) and (3) of this subsection, shall include carrying costs on the positive or negative fuel balance equal to:

(A) the weighted-average cost of capital approved in the company's unbundled cost of service (UCOS) proceeding, if the period until the date of the final true-up order is greater than one year; or

(B) the rate approved in §25.236 of this title (relating to Recovery of Fuel Costs) if the period until the date of the final true-up order is one year or less.

(i) **True-up of capacity auction proceeds.**

(1) For purposes of the true-up required by PURA §39.262(d)(2), and as provided for under §25.381(h)(1) of this title (relating to Capacity Auctions), the APGC shall compute the difference between the price of power obtained through the capacity auctions conducted for the years 2002 and 2003 and the power cost projections for the same time period as used in the determination of ECOM for that utility in the proceeding under PURA §39.201. The difference shall be calculated according to the following formula: (ECOM market revenues – ECOM fuel costs) – ((capacity auction price x total 2002 and 2003 busbar sales) – actual 2002 and 2003 fuel costs). For purposes of this paragraph:

(A) "ECOM market revenues" shall be the sum of rows 12 through 14 for the years 2002 and 2003 in the "Plant Economics" worksheet of the ECOM model underlying the commission-approved ECOM estimate in the company's UCOS proceeding;

(B) "ECOM fuel costs" shall be the sum of rows 33 through 35 for the years 2002 and 2003 in the "Cost Partition" worksheet of the ECOM model underlying the commission-approved ECOM estimate in the company's UCOS proceeding;

(C) The "capacity auction price" shall be the APGC's total capacity auction revenues derived from the capacity auctions conducted for the years 2002 and 2003 divided by that APGC's total MWh sales of capacity auction products for the years 2002 and 2003.

(2) If, as a result of not having participated in capacity auctions pursuant to §25.381(h)(1) of this title, an APGC is unable to determine a company-specific capacity auction price, the APGC may request in its true-up application a method using prevailing capacity auction prices from other APGCs for the calculation in paragraph (1) of this subsection.

(j) **True-up of PTB revenues.** This subsection specifies how the PTB will be compared to prevailing market prices pursuant to PURA §39.262(e). For purposes of this subsection, the term "small commercial customer" does not include unmetered lighting accounts unless such an account has historically been treated as a separate customer for billing purposes.

(1) An AREP is not required to perform the reconciliation described in PURA §39.262(e) for the residential or small commercial customer class if the commission has determined that the AREP has reached the applicable 40% threshold requirements prior to January 1, 2004, pursuant to filing requirements listed in §25.41(l) of this title (relating to Price to Beat) applicable to that class.

(2) If an AREP has not reached the applicable 40% threshold requirements prior to January 1, 2004, for either the residential or the small commercial class, or both, the net PTB for each such class must be compared to the market price of electricity for that class in the TDU region for the period January 1, 2002 through January 1, 2004 as provided in paragraphs (3) and (4) of this subsection.

(3) The independent third party shall compute the difference between the residential net PTB and the residential market price of electricity on the last day of each calendar-year quarter for the years 2002 and 2003. The price differential for each quarter shall be multiplied by the total kWh consumed by residential PTB customers of the AREP for that quarter. The results shall be summed over the eight quarters within the period from January 1, 2002 through January 1, 2004.

(4) The independent third party shall compute the difference between the small commercial net PTB and the small commercial market price of electricity on the last day of each calendar-year quarter for the years 2002 and 2003. The price differential for each quarter shall be multiplied by the total kWh consumed by small commercial PTB customers of the AREP for that quarter. The results shall be summed over the eight quarters within the period from January 1, 2002 through January 1, 2004.

(5) For each of the residential and small commercial classes, the AREP shall credit the TDU the lesser of the amounts calculated in subparagraphs (A) and (B) of this paragraph:

(A) $150 multiplied by (the difference between the number of residential or small commercial customers, as applicable, in the TDU Region taking PTB service from the AREP on January 1, 2004 and the number of residential or small commercial customers, as applicable, outside the TDU region being served by the AREP on January 1, 2004, provided that such customers are not receiving POLR service from the AREP); or

(B) the total differential between the net PTB and the market price of electricity calculated for the applicable class under paragraph (3) or (4) of this subsection.

(6) All REPs shall provide information to the independent third party as needed for the performance of calculations set forth in paragraphs (3) and (4) of this subsection. All data used in the calculations performed by the independent third party will remain confidential but shall be subject to audit by the commission.

(7) The functions of the independent third party shall be funded by the AREPs through one or more assessments made by the commission.

(k) **Regulatory assets.** To the extent that any amount of regulatory assets included in a TC or CTC exceeds the amount of regulatory assets approved in a rate order which became effective on or before September 1, 1999, the commission shall conduct a review during the true-up proceeding to determine any such amounts that were not appropriately calculated or that did not constitute reasonable and necessary costs. In addition, to the extent that any amount of regulatory assets approved for securitization in a commission financing order was not subsequently included in an issuance of transition bonds, that amount of regulatory assets shall be included in the TDU/APGC true-up balance under subsection (l) of this section.

(l) **TDU/APGC True-up balance.**

(1) The formula to establish the true-up balance between the TDU and APGC is shown in the following table. TDUs described in subsection (d)(3) of this section and their APGCs shall insert zero for all inputs in this equation except the input entitled "Final fuel balance calculated pursuant to subsection (h)."

Calculation of True-up Balance	
	Net book value calculated pursuant to subsection (g)
-	Market value calculated pursuant to subsection (f)(1)
+/-	Value calculated by ECOM model pursuant to subsection (f)(2)
+/-	Final fuel balance calculated pursuant to subsection (h)
+/-	Capacity auction true-up calculated pursuant to subsection (i)
+/-	Regulatory asset amount calculated pursuant to subsection (k)
=	TDU/APGC True-up Balance

(2) For TDUs described in subsection (d)(2) of this section, the TDU/APGC true-up balance shall be compared to projected stranded costs as provided in subparagraphs (A) – (C) of this paragraph. For TDUs described in subsection (d)(3) of this section, the TDU/APGC true-up balance shall be treated as provided in subparagraph (D) of this paragraph.

(A) If the TDU/APGC true-up balance is positive, and greater than projected stranded costs, then the commission shall increase the CTC (or establish a CTC, if no CTC has previously been approved for the utility), extend the time for the collection of the CTC, or both, to enable the TDU to collect the TDU/APGC true-up balance. The utility may seek to securitize any or all of the amounts determined under this subparagraph under PURA Chapter 39, Subchapter G.

(B) If the TDU/APGC true-up balance is positive, but less than projected stranded costs, then the commission shall reduce nonbypassable delivery rates in the amount of the difference by:

(i) reducing any CTC established under PURA §39.201;

(ii) reversing, in whole or in part, the depreciation expense that has been redirected under PURA §39.256;

(iii) reducing the TDU's rates; or

(iv) any combination of clauses (i), (ii), and (iii) of this subparagraph.

(C) If the TDU/APGC true-up balance is negative, then

(i) any CTC established under PURA §39.201 shall be eliminated;

(ii) net mitigation shall be reversed until exhausted or until a zero true-up balance is achieved, and the amount of net mitigation reversed shall be returned to ratepayers by the APGC through an excess mitigation credit; and

(iii) if net mitigation is exhausted and some amount of the negative true-up balance remains, then for companies that have securitized regulatory assets, a negative CTC shall be established based upon the lesser of the absolute value of the remaining negative true-up balance or the securitization amount on which any TCs are based. If the company has been issued a financing order by the commission authorizing the securitization of regulatory assets but securitization has not yet occurred, then the negative CTC will be implemented at the time the securitization bonds are issued. If the company has not received a financing order from the commission authorizing securitization of regulatory assets, then no negative CTC shall be established for purposes of this subsection.

(D) If the TDU/APGC true-up balance is positive, then a CTC shall be imposed to enable the APGC to recover any positive fuel balance. If the TDU/APGC true-up balance is negative, then a fuel credit shall be implemented to return the over-recovered fuel balance to ratepayers.

(3) The TDU shall be allowed to recover, or shall be liable for, carrying costs on the true-up balance. This provision shall apply to all amounts the commission has authorized to be collected under this section that have not been securitized. Carrying costs on the unrecovered true-up balance shall be calculated from January 1, 2002, until the true-up balance is fully recovered. Based on the filing described below that is made within 30 days of the effective date of this rule, carrying costs shall be calculated using an interest rate determined as follows.

(A) The TDU shall file an application to adjust the carrying costs and amend its CTC tariff on a prospective basis in conformance with this paragraph within 30 days of the effective date of an amendment to this paragraph. The establishment of the interest rate used to calculate carrying charges shall be based upon the following:

(i) The weighted average of the TDU's unadjusted historical cost of debt (HC) and an adjusted form of the TDU's marginal cost of debt (MC), with the weightings based on the utility's most recently authorized capital structure. The HC component shall be the cost of debt as determined in a final commission order, provided that the order was entered within three years of the effective date of this rule, for a rate proceeding in which the TDU's cost of debt was explicitly addressed or can be determined based upon the order's authorized weighted-average cost of capital (overall rate of return on invested capital), proportions of debt and equity, and allowed return on equity. The MC component shall be based upon the average yield for long-term bonds of public utilities with the TDU's current credit rating during the three-month period preceding the filing, as published in *Moody's Credit Perspectives* (or a similar publication if *Moody's Credit Perspectives* is not available). Additionally, the MC component shall be adjusted—*i.e.*, grossed-up—for the effects of federal income taxes. The following formula shall be used to determine the weighted-average carrying cost described above:

CTC Carrying Charge Rate = MC * Equity Proportion of Most Recently Authorized Capital Structure * 1/(1-Tax Rate) + HC * Debt Proportion of Most Recently Authorized Capital Structure

(ii) If the commission, within three years prior to the effective date of this rule, did not enter a final order in a rate proceeding that addresses the TDU's cost of debt, the HC component used in the interest rate determination described in the preceding clause shall be based upon the cost of debt reported in the utility's most recent Earnings Monitoring Report filed pursuant to §25.73 of this title (relating to Financial and Operating Reports), adjusted for known and measurable changes.

(B) In each rate case for the TDU, the calculation of carrying costs on the TDU's unsecuritized true-up balance shall be reviewed and adjusted to reflect authorized changes in the TDU's capital structure and cost of debt. Further, to reflect the effect of the CTC carrying charge rate across the entirety of the TDU's recoverable regulated assets, a composite rate of return incorporating the CTC carrying charge rate may be applied to both the unsecuritized true-up balance and the TDU rate base. The composite rate of return shall be calculated as follows:

Composite Pre-Tax Rate of Return = CTC Carrying Charge Rate * Unsecuritized True-up Balance / (Unsecuritized True-up Balance + TDU Rate Base) + TDU Authorized Pre-Tax Weighted-Average Cost of Capital * TDU Rate Base / (Unsecuritized True-up Balance + TDU Rate Base)

(m) **TDU/AREP true-up balance.** The TDU shall bill the AREP for, and the AREP shall remit to the TDU, the amount calculated pursuant to subsection (j) of this section, plus carrying costs. Carrying costs shall be calculated in accordance with subsection (l) of this section and shall be calculated for the period of time from the date of the true-up final order until fully recovered. The commission may reduce the TDU's rates to reflect the amounts due from the AREP.

(n) **Proceeding subsequent to the true-up.**

(1) The TDU shall file an application to adjust its rates within 60 days following the issuance of a final, appealable order in its true-up proceeding. In the proceeding, the commission may adjust the TDU's rates and any CTC, in accordance with PURA §39.262(g), and any excess mitigation credit.

The commission may also allocate the recovery responsibility for such rates and any CTC to the TDU's customer classes.

(2) In the proceeding, the commission shall also consider adopting remittance standards, if necessary, with respect to the credits or bills as among the TDU, the APGC, and the AREP.

§25.264. Quantification of Stranded Costs of Nuclear Generation Assets.

The market value of an affiliated power generation company's nuclear assets may be established by compliance with any of the four methods of quantification specified in Public Utility Regulatory Act (PURA) §39.262(h) and related requirements specified in §25.263 of this title (relating to True-up Proceeding). If the electric utility or its affiliated power generation company values some of its assets using the sale of assets or an exchange of assets, any remaining assets shall be combined in one or more transferee corporations as described in PURA §39.262(h)(2) and (3) for purposes of determining their market value, or the electric utility or its affiliated power generation company shall quantify its stranded costs for remaining nuclear assets using the "excess costs over market" or ECOM method.

§25.265. Securitization by River Authorities and Electric Cooperatives.

(a) **Application.** This section applies to securitization transactions carried out by a river authority or electric cooperative. A river authority or electric cooperative may adopt and use securitization provisions having the effect of the provisions provided by the Public Utility Regulatory Act (PURA), Chapter 39, Subchapter G, to recover its stranded costs in accordance with this section.

(b) **Definition of stranded costs.**

(1) For electric cooperatives, the term "stranded costs" when used in this section shall mean "stranded investment" as defined in PURA §41.002(3).

(2) For river authorities, the term "stranded costs" when used in this section shall mean the positive excess of the combined net book value of generation assets over the combined market value of the assets, taking into account all of the river authority's generation assets, any above market purchased power costs, and any deferred debit related to a utility's discontinuance of the application of Statement of Financial Accounting Standards Number 71 ("Accounting for the Effects of Certain Types of Regulation") for generation-related assets.

(c) **Quantification of stranded costs.** Only those river authorities and electric cooperatives having positive stranded costs as determined by this section may securitize such costs.

(1) For electric cooperatives, the board of directors has the exclusive jurisdiction to reasonably determine the amount of the electric cooperative's stranded investments.

(2) For river authorities, the governing body shall determine the amount of stranded costs using an administrative model or other reasonable methodology, and such determinations shall be subject to review and approval by the commission.

(d) **Demonstration of tangible and quantifiable benefits to ratepayers.** A river authority or electric cooperative may not utilize securitization financing to recover stranded costs unless it demonstrates that securitization provides tangible and quantifiable benefits to ratepayers greater than would have been achieved absent the issuance of transition bonds. Such demonstration shall be performed on an asset-by-asset basis.

(e) **Limit on amount of qualified costs to be securitized.** The amount securitized may not exceed the sum of:

(1) the present value, calculated using a discount rate equal to the proposed interest rate on the transition bonds, of the revenue requirement over the life of the proposed transition bonds associated with the stranded costs sought to be securitized, and

(2) the costs of issuing, supporting, and servicing the transition bonds and any costs of retiring and refunding existing debt of the river authority or electric cooperative.

(f) **Use of proceeds.** The proceeds of the transition bonds shall be used solely for the purpose of reducing the amount of recoverable stranded costs as determined pursuant to this section, through the refinancing or retirement of debt of the river authority or electric cooperative.

(g) **True-up in the event of sale.** A river authority or electric cooperative shall not overrecover its stranded costs. If the recovery of an asset has been securitized through a sale of transition bonds, and the asset is subsequently sold in a bona fide third-party transaction, then that asset shall be subject to true-up. To the extent the total net value received from the sale of such asset exceeds its remaining book value, the river authority or electric cooperative shall make refunds of the entire overcollected amounts, with interest, to its ratepayers through an appropriate mechanism.

(h) **Recovery of stranded costs.** An electric cooperative or river authority may recover its securitized stranded costs and the reasonable costs of issuing, supporting, and servicing the transition bonds through a transition charge.

(1) **Electric Cooperatives.** An electric cooperative may recover its stranded costs through transition charges from all existing or future customers, including the facilities, premises and loads of those customers taking service from the cooperative as of May 1, 1999. An electric cooperative's board of directors has the exclusive jurisdiction to establish non-discriminatory transition charges reasonably designed to recover the stranded costs over an appropriate period of time consistent with this section.

(2) **River Authorities.** A river authority may recover its qualified costs, as defined in PURA, Chapter 39, Subchapter G, including its stranded costs as defined herein, through transition charges reasonably designed to recover the stranded costs over an appropriate period of time consistent with this section. Payment of transition charges shall be made by customers taking service from the river authority as of May 1, 1999 or those customers' successors or assigns. Transition charges of a river authority in a financing order adopted pursuant to this section shall be collected by the river authority, and such charges shall not be subject to challenge provided that a river authority's determination as to the existence and amount of stranded costs has been approved under subsections (b) and (c) of this section.

(3) **Transition charges for both electric cooperatives and river authorities.**

(A) The transition charge shall be sufficient to recover the stranded costs at the level, up to 100%, deemed appropriate by the electric cooperative or river authority.

(B) Any transition charges adopted in accordance with this section shall constitute property rights, as described in PURA, Chapter 39, Subchapter G, and otherwise conform in all material respects to the transition charges provided by PURA, Chapter 39, Subchapter G.

(C) A river authority or electric cooperative may recover a transition charge notwithstanding the expiration of a wholesale contract.

(i) **Financing order**. A cooperative or river authority which chooses to adopt and use securitization provisions shall adopt a financing order consistent with this section.

(1) The financing order shall contain a finding that the present value total amount of revenues to be collected under the financing order is less than the present value of the revenue requirement that would be recovered over the remaining life of the stranded costs using conventional financing methods.

(2) The financing order shall have the effects of the provisions provided by PURA, Chapter 39, Subchapter G. The effects shall be detailed in the financing order and shall include, but are not limited to, provisions regarding property rights, set-off, security interests, no bypass, true-up, true sale, and security interests.

(3) The financing order shall detail the stranded costs to be recovered and the period over which the nonbypassable transition charges shall be recovered, which period may not exceed 15 years.

(4) The financing order shall detail how the proceeds from the transition bond are being used to refinance or retire river authority or cooperative debt as prescribed by subsection (f) of this section.

(5) The financing order shall contain findings detailing the tangible and quantifiable benefits as prescribed by subsection (d) of this section.

(6) The financing order shall contain a finding that the amount to be securitized does not exceed the limit on qualified costs as prescribed in subsection (e) of this section.

(7) The financing order shall detail the allocation of the stranded costs to applicable classes and the corresponding design of transition charges.

(8) The financing order shall provide for a structure and pricing of the transition bonds that results in the lowest transition charges consistent with market conditions.

(9) The financing order shall include a mechanism requiring that transition charges be reviewed and adjusted at least annually, within 45 days of the anniversary date of the issuance of the transition bonds, to correct any overcollections or undercollections of the preceding 12 months and to ensure the expected recovery of amounts sufficient to timely provide all payments of debt service and other required amounts and charges in connection with the transition bonds.

(10) The financing order shall become effective in accordance with its terms, and the financing order, together with the transition charges, shall thereafter be irrevocable and not subject to reduction, impairment, or adjustment by further action of the cooperative, river authority or the commission, except for periodic true-ups as specified in this section.

(11) Findings made by the governing body of the electric cooperative or river authority under the rules and procedures described in this section shall be conclusive, subject to the provisions of subsection (c)(2) of this section.

§25.271. Foreign Utility Company Ownership by Exempt Holding Companies.

(a) **Certification to Securities and Exchange Commission.** Upon request by a holding company which is exempt under §3 of the Public Utility Holding Company Act of 1935, codified at 15 United States Code 79, the commission may certify to the Securities and Exchange Commission (SEC) that the commission has the authority and resources to protect ratepayers and that it intends to exercise its authority over holding companies owning both a jurisdictional electric utility and a foreign utility company (FUCO) under the safe harbor provisions of subsection (c) of this section or the case-by-case review provisions of subsection (d) of this section. The commission may also notify the SEC that a previously-issued certification regarding a requesting holding company will be ineffective prospectively.

(b) **Policy goals.** The commission will seek to protect the public interest in having electricity service available to all citizens of the state at just, fair, and reasonable rates that are unaffected by investments by exempt holding companies in foreign utility companies (FUCOs), while avoiding strictures that would place exempt holding companies at a competitive disadvantage in international markets. The commission will consider these policy goals in each decision whether to issue a certification or to notify the SEC that a previously-issued certification is prospectively withdrawn.

(c) **Safe harbor investments.** The following safe harbor provisions shall be applicable to investments in FUCOs by exempt holding companies that are affiliated with electric utilities subject to the regulatory jurisdiction of the commission:

(1) The commission shall certify to the SEC that the commission has the authority and resources to protect ratepayers subject to its jurisdiction and that it intends to exercise its authority, provided that all holding companies of electric utilities that are subject to the regulatory jurisdiction of this commission shall have filed with the commission corporate undertakings, signed under oath by an authorized executive officer of the holding company agreeing to adhere to the covenants and to make the filings specified in paragraph (2) of this subsection.

(2) The holding company shall adhere to the following covenants:

(A) That any indebtedness incurred in relation to the acquisition by the holding company, or by any affiliate of the electric utility, of an ownership interest in a FUCO will be without recourse to the electric utility;

(B) That the electric utility, the holding company, or any affiliate of the electric utility will not enter into any agreements under the terms of which the electric utility is obligated to commit funds in order to maintain the financial viability of a FUCO or an affiliate of the electric utility investing in a FUCO;

(C) That the electric utility will not provide, directly or indirectly, any guarantees or other forms of credit support for any funds borrowed by the holding company or an affiliate of the electric utility in connection with the acquisition of any ownership interest in a FUCO;

(D) That the electric utility, the holding company, or any affiliate of the electric utility will not make any investment in a FUCO under circumstances in which the electric utility would be liable for the debts and/or liabilities of the FUCO incurred as a result of acts or omissions of the FUCO;

(E) That the electric utility will maintain and provide a copy to the commission of its accounting policies and procedures that assure that the electric utility is adequately and fairly compensated by the holding company or an affiliate of the electric utility for any use of the electric utility's assets or personnel in furtherance of a FUCO;

(F) That the holding company provides the commission reasonable access to books and records and financial statements, or copies thereof, of the FUCO or other affiliate doing business with the FUCO, in English and stated in United States dollars, as the commission may request to:

(i) review transactions between the electric utility and such FUCO or affiliate pursuant to the Public Utility Regulatory Act §14.154; and

(ii) review transactions between any affiliate and the FUCO if such affiliate also has transactions directly or indirectly with the electric utility;

(G) That the holding company will file with the commission quarterly a report listing the total amount of the aggregate investments by the holding company and its subsidiaries and the percentage of the holding company's consolidated net worth, from the company's most recent SEC form 10-Q, represented by such investments;

(i) "Aggregate investment" means all amounts invested, or committed to be invested, in exempt wholesale generators located outside the United States (foreign EWGs) and FUCOs, for which there is recourse, directly or indirectly, to the holding company. Among other things, the term shall include preliminary development expenses that culminate in the acquisition of a foreign EWG or a FUCO.

(ii) Such report shall be filed no later than ten days following the filing of the 10-Q for the quarter.

(H) That in the event the holding company anticipates making any investment in a FUCO that would result in the aggregate investment as defined in subparagraph (G) of this paragraph of such holding company exceeding 30% of the consolidated net worth of such holding company, the holding company shall so advise the commission before a final commitment to ownership of such FUCO is made;

(I) That the electric utility will provide, by March 31 of each year, a copy of the electric utility's three-year cash flow forecast;

(J) That the holding company will provide to the commission all SEC forms for reporting information related to foreign EWG and FUCO investments, no later than ten days after such forms are provided to the SEC;

(K) That the holding company will promptly notify the commission whenever any of the following occurs:

(i) It is unable to provide the certifications, undertakings, or documents provided for in this paragraph;

(ii) The aggregate investment exceeds 30% of consolidated net worth;

(iii) The holding company's operating losses attributable to its direct or indirect investments in foreign EWGs and FUCOs exceeded 5.0% of consolidated retained earnings during the previous four quarters; and

(L) That the holding company will comply with the informational filing requirements of subsection (d) of this section in connection with a contemplated investment in a FUCO, unless the commission finds good cause not to require the holding company to provide such additional information.

(d) **Other investments.** For any occasion for which a holding company has undertaken to notify the commission of an event specified in subsection (c)(2)(H) or (K) of this section, the following provisions apply:

(1) The holding company shall provide the following information, to the extent such information is reasonably available at the time of submission of the filing, at least 30 days before the date when it anticipates making a final commitment to ownership of a FUCO not already covered by a certification letter:

(A) A description of the proposed investment, including a description of the FUCO assets being acquired, their geographical location, the form of the investment (partnership, joint venture, direct purchase, etc.), the holding company's percentage share of the investment, a description of how the investment will fit into the corporate subsidiary structure, and any other information reasonably necessary in the opinion of the holding company to provide a complete overview of the nature of the proposed investment;

(B) Any financial requirements and/or commitments by the holding company or the electric utility that will be made or assumed as a result of this investment; this information should include, but is not limited to, an estimate of the amount of equity capital to be invested;

(C) Any debt obligations resulting from this investment which will provide recourse to the holding company or the electric utility;

(D) The holding company's general corporate objectives regarding diversification and foreign utility investments, and the specific objectives of the proposed FUCO investment;

(E) A statement that the electric utility has effective written policies and accounting procedures which insure that any use by the FUCO of assets or personnel of an affiliate of the electric utility, or other transactions between the FUCO and an affiliate of the electric utility shall not negatively affect Texas ratepayers; and a statement that the electric utility will demonstrate in each subsequent rate proceeding before the commission, and each subsequent audit, that no FUCO investment increased the cost of capital or revenue requirement of the electric utility;

(F) A calculation, based on the holding company's most recent SEC Form 10-Q, of aggregate consolidated holding company investments as defined in subsection (c)(2)(G) of this section as a percentage of consolidated holding company net worth, stated both before and after all asset transfers from any affiliate of the electric utility to FUCOs at fair market value;

(G) A statement that the holding company will provide to the commission all SEC forms for reporting information related to foreign EWG and FUCO investments, no later than ten days after such forms are provided to the SEC; and

(H) Responses to questions, if any, contained on a commission prescribed form.

(2) The notification prescribed in this subsection may be submitted less than 30 days before the date when the holding company anticipates making a final commitment to ownership of a FUCO not already covered by a certification letter upon a showing of good cause. Good cause for purposes of the preceding sentence shall be deemed to include, without limitation, a representation that the holding company lacked the information required to make a submission at an earlier date or a representation that making the submission at an earlier date would have unreasonably jeopardized the ability of the holding company to go forward with the contemplated investment.

(3) In its review of the information provided pursuant to this section, the commission will consider, among other things, the number and magnitude of prior FUCO investments by the holding company, including the diversity among the countries in which such investments are located and other differences between such investments, and the magnitude of the proposed investment and its effect on the diversity of the portfolio.

(e) **Post-investment reporting**. The electric utility shall comply with the following post-investment reporting obligations:

(1) With respect to any investment in a FUCO for which an informational filing was made pursuant to subsection (d)(1) of this section, the electric utility or holding company shall notify the commission no later than ten days after the holding company makes a final commitment to ownership of a FUCO that such a commitment has been made. Such notice shall include any material corrections, additions, and supplementation of previously-provided information; and

(2) For any FUCO investment covered by a certification, the electric utility or holding company shall notify the commission no later than 30 days after any material change in the circumstances or nature of an investment in a FUCO. Such notice shall include all appropriate corrections, additions, and supplementation of previously-provided information. A material change would include, but is not limited to, any change that would have an adverse impact of greater than 1.0% of consolidated net worth most recently reported; full or partial divestiture of the investment; a catastrophic event that destroys a significant amount of FUCO property or results in loss of life that could result in a

significant liability claim; a change in the laws or government policy having a material impact on the FUCO; or an event which would place a significant restriction on the repatriation of earnings of the FUCO.

(3) Unless included in SEC reports, each exempt utility holding company which directly or indirectly holds an interest in FUCOs or foreign EWGs shall provide the following information: A consolidating statement of income of the exempt holding company and its subsidiary companies for the last calendar year, together with a consolidating balance sheet of the exempt holding company and its subsidiary companies as of the close of such calendar year.

(A) The information shall be provided in English, monetary amounts in U.S. dollars, and according to generally accepted accounting principles.

(B) Such information must be received by the commission annually no later than March 15.

(f) **Commission standards for granting or maintaining certification.**

(1) In general, the commission will issue and continue certification when the aggregate investment in FUCOs and foreign EWGs is less than 30% of the holding company's consolidated net worth, and the company has satisfactorily provided the information and assurances set out in the preceding subsections.

(2) With respect to any investment in a FUCO for which an informational filing was made pursuant to subsection (d)(1) of this section, the commission shall determine on a case by case basis whether to issue a certification to the SEC or maintain a previously issued certification. The commission shall endeavor to make such a determination prior to the date when the holding company anticipates having to make a final commitment to ownership of the FUCO. If the commission determines that it does not intend to continue certification, it may inform the SEC that maintaining a previously-issued certification would be inappropriate.

(3) The commission shall notify the holding company requesting the certification or retention of certification of its decision within 45 days of receiving the request. If no action is taken by the commission within 45 days of receiving the request, the certification shall be deemed granted or affirmed.

(4) Any information submitted by a holding company pursuant to this section may be submitted by the holding company under seal. Each page tendered under seal shall have the words "Confidential Information" typed or stamped on its face. The holding company shall clearly identify each portion of the application alleged to be Confidential Information; identify the exemption to the Public Information Act, Texas Government Code Annotated, Chapter 552 (Vernon Supp. 1998), applicable to the alleged Confidential Information; and provide a detailed explanation of why the alleged Confidential Information is exempt from public disclosure under the Public Information Act. If the commission receives a Public Information Act request for disclosure of Confidential Information, then the Executive Director shall promptly so notify the holding company. The Executive Director shall timely request an Attorney General's opinion as to whether the information falls within any of the exemptions identified in Subchapter C of the Public Information Act. The Executive Director shall promptly provide to the holding company a copy of an Attorney General opinion regarding the claim of confidentiality. If an Attorney General opinion recommends disclosure of Confidential Information, either in whole or in part, then the Executive Director shall not release such information for ten calendar days, in order to allow the holding company time to pursue any legal remedies that it may have. The holding company may require the execution of an appropriate confidentiality agreement prior to providing access to such confidential information to the Legal Division of the Office of Regulatory Affairs or other interested party. The form of any such confidentiality agreement shall be approved by the Legal Division prior to filing and included with the informational filing.

§25.272. Code of Conduct for Electric Utilities and Their Affiliates.

(a) **Purpose.** The provisions of this section establish safeguards to govern the interaction between utilities and their affiliates, both during the transition to and after the introduction of competition, to avoid potential market-power abuses and cross-subsidization between regulated and unregulated activities.

(b) **Application.**

(1) **General application.** This section applies to:

(A) electric utilities operating in the State of Texas as defined in the Public Utility Regulatory Act (PURA) §31.002(6), and transactions or activities between electric utilities and their affiliates, as defined in PURA §11.003(2); and

(B) transmission and distribution utilities operating in a qualifying power region in the State of Texas as defined in PURA §31.002(19) upon commission certification of a qualifying power region pursuant to PURA §39.152, and transactions or activities between transmission and distribution utilities and their affiliates, as defined in PURA §11.003(2).

(2) **No circumvention of the code of conduct**. An electric utility, transmission and distribution utility, or competitive affiliate shall not circumvent the provisions or the intent of PURA §39.157 or any rules implementing that section by using any affiliate to provide information, services, products, or subsidies between a competitive affiliate and an electric utility or a transmission and distribution utility.

(3) **Notice of conflict and/or petition for waiver.** Nothing in this section is intended to affect or modify the obligation or duties relating to any rules or standards of conduct that may apply to a utility or the utility's affiliates under orders or regulations of the Federal Energy Regulatory Commission (FERC) or the Securities and Exchange Commission (SEC). A utility shall file with the commission a notice of any provision in this section that conflict with FERC or SEC orders or regulations. A utility that is subject to statutes or regulations in any state that conflict with a provision of this section may petition the commission for a waiver of the conflicting provision on a showing of good cause.

(c) **Definitions.** The following words and terms when used in this section shall have the following meaning unless the context clearly indicates otherwise:

(1) **Arm's length transaction --** The standard of conduct under which unrelated parties, each acting in its own best interest, would carry out a particular transaction. Applied to related parties, a transaction is at arm's length if the transaction could have been made on the same terms to a disinterested third party in a bargained transaction.

(2) **Competitive affiliate --** An affiliate of a utility that provides services or sells products in a competitive energy-related market in this state, including telecommunications services, to the extent those services are energy-related.

(3) **Confidential information --** Any information not intended for public disclosure and considered to be confidential or proprietary by persons privy to such information. Confidential information includes but is not limited to information relating to the interconnection of customers to a utility's transmission or distribution systems, proprietary customer information, trade secrets, competitive information relating to internal manufacturing processes, and information about a utility's transmission or distribution system, operations, or plans for expansion.

(4) **Corporate support services** -- Services shared by a utility, its parent holding company, or a separate affiliate created to perform corporate support services, with its affiliates of joint corporate oversight, governance, support systems, and personnel. Examples of services that may be shared, to the extent the services comply with the requirements prescribed by PURA §39.157(d) and (g) and rules implementing those requirements, include human resources, procurement, information

technology, regulatory services, administrative services, real estate services, legal services, accounting, environmental services, research and development unrelated to marketing activity and/or business development for the competitive affiliate regarding its services and products, internal audit, community relations, corporate communications, financial services, financial planning and management support, corporate services, corporate secretary, lobbying, and corporate planning. Examples of services that may not be shared include engineering, purchasing of electric transmission facilities and service, transmission and distribution system operations, and marketing, unless such services are provided by a utility, or a separate affiliate created to perform such services, exclusively to affiliated regulated utilities and only for provision of regulated utility services.

(5) **Proprietary customer information --** Any information compiled by an electric utility on a customer in the normal course of providing electric service that makes possible the identification of any individual customer by matching such information with the customer's name, address, account number, type or classification of service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges, billing records, or any other information that the customer has expressly requested not be disclosed. Information that is redacted or organized in such a way as to make it impossible to identify the customer to whom the information relates does not constitute proprietary customer information.

(6) **Similarly situated** -- The standard for determining whether a non-affiliate is entitled to the same benefit a utility offers, or grants upon request, to its competitive affiliate for any product or service. For purposes of this section, all non-affiliates serving or proposing to serve the same market as a utility's competitive affiliate are similarly situated to the utility's competitive affiliate.

(7) **Transaction** -- Any interaction between a utility and its affiliate in which a service, good, asset, product, property, right, or other item is transferred or received by either a utility or its affiliate.

(8) **Utility --** An electric utility as defined in PURA §31.002(6) or a transmission and distribution utility as defined in PURA §31.002(19). For purposes of this section, a utility does not include a river authority operating a steam generating plant on or before January 1, 1999, or a corporation authorized by Chapter 245, Acts of the 67th Legislature, Regular Session, 1981 (Article 717 p, Vernon's Texas Civil Statutes). In addition, with respect to a holding company exempt under the Public Utility Holding Company Act (PUHCA) §3(a)(2), the term "utility," as used in this section, means the division or business unit through which the holding company conducts utility operations and not the holding company as a legal entity.

(d) **Separation of a utility from its affiliates**.

(1) **Separate and independent entities.** A utility shall be a separate, independent entity from any competitive affiliate.

(2) **Sharing of employees, facilities, or other resources.** Except as otherwise allowed in paragraphs (3), (4), (5), or (7) of this subsection, a utility shall not share employees, facilities, or other resources with its competitive affiliates unless the utility can prove to the commission prior to such sharing that the sharing will not compromise the public interest. Such sharing may be allowed if the utility implements adequate safeguards precluding employees of a competitive affiliate from gaining access to information in a manner that would allow or provide a means to transfer confidential information from a utility to an affiliate, create an opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross-subsidization of affiliates.

(3) **Sharing officers and directors, property, equipment, computer systems, information systems, and corporate services.** A utility and a competitive affiliate may share common officers and directors, property, equipment, computer systems, information systems and corporate

support services, if the utility implements safeguards that the commission determines are adequate to preclude employees of a competitive affiliate from gaining access to information in a manner that would allow or provide a means to transfer confidential information from a utility to an affiliate, create an opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross-subsidization of affiliates

(4) **Employee transfers and temporary assignments.** A utility shall not assign, for less than one year, utility employees engaged in transmission or distribution system operations to a competitive affiliate unless the employee does not have knowledge of confidential information. Utility employees engaged in transmission or distribution system operations, including persons employed by a service company affiliated with the utility who are engaged in transmission system operations on a day-to-day basis or have knowledge of transmission or distribution system operations and are transferred to a competitive affiliate, shall not remove or otherwise provide or use confidential property or information gained from the utility or affiliated service company in a discriminatory or exclusive fashion, to the benefit of the competitive affiliate or to the detriment of non-affiliated electric suppliers. Movement of an employee engaged in transmission or distribution system operations, including a person employed by a service company affiliated with the utility who is engaged in transmission or distribution system operations on a day-to-day basis or has knowledge of transmission or distribution system operations from a utility to a competitive affiliate or vice versa, may be accomplished through either the employee's termination of employment with one company and acceptance of employment with the other, or a transfer to another company, as long as the transfer of an employee from the utility to an affiliate results in the utility bearing no ongoing costs associated with that employee. Transferring employees shall sign a statement indicating that they are aware of and understand the restrictions and penalties set forth in this section. The utility also shall post a conspicuous notice of such a transfer on its Internet site or other public electronic bulletin board within 24 hours and for at least 30 consecutive calendar days. The exception to this provision is that employees may be temporarily assigned to an affiliate or non-affiliated utility to assist in restoring power in the event of a major service interruption or assist in resolving emergency situations affecting system reliability. Consistent with §25.84(h) of this title, however, within 30 days of such a deviation from the code of conduct, the utility shall report this information to the commission and shall conspicuously post the information on its Internet site or other public electronic bulletin board for 30 consecutive calendar days.

(5) **Sharing of office space.** A utility's office space shall be physically separate from that of its competitive affiliates, where physical separation is accomplished by having office space in separate buildings or, if within the same building, by a method such as having offices on separate floors or with separate access, unless otherwise approved by the commission.

(6) **Separate books and records.** A utility and its affiliates shall keep separate books of accounts and records, and the commission may review records relating to a transaction between a utility and an affiliate.

(A) In accordance with generally accepted accounting principles or state and federal guidelines, as appropriate, a utility shall record all transactions with its affiliates, whether they involve direct or indirect expenses.

(B) A utility shall prepare financial statements that are not consolidated with those of its affiliates.

(C) A utility and its affiliates shall maintain sufficient records to allow for an audit of the transactions between the utility and its affiliates. At any time, the commission may, at its discretion, require a utility to initiate, at the utility's expense, an audit of transactions between the utility and its affiliates performed by an independent third party.

(7) **Limited credit support by a utility.** A utility may share credit, investment, or financing arrangements with its competitive affiliates if it complies with subparagraphs (A) and (B) of this

paragraph.

(A) The utility shall implement adequate safeguards precluding employees of a competitive affiliate from gaining access to information in a manner that would allow or provide a means to transfer confidential information from a utility to an affiliate, create an opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross- subsidization of affiliates.

(B) The utility shall not allow an affiliate to obtain credit under any arrangement that would include a specific pledge of any assets in the rate base of the utility or a pledge of cash reasonably necessary for utility operations. This subsection does not affect a utility's obligations under other law or regulations, such as the obligations of a public utility holding company under §25.271(c)(2) of this title (relating to Foreign Utility Company Ownership by Exempt Holding Companies).

(e) **Transactions between a utility and its affiliates.**

(1) **Transactions with all affiliates.** A utility shall not subsidize the business activities of any affiliate with revenues from a regulated service. In accordance with PURA and the commission's rules, a utility and its affiliates shall fully allocate costs for any shared services, including corporate support services, offices, employees, property, equipment, computer systems, information systems, and any other shared assets, services, or products.

(A) **Sale of products or services by a utility.** Unless otherwise approved by the commission and except for corporate support services, any sale of a product or service by a utility shall be governed by a tariff approved by the commission**.** Products and services shall be made available to any third party entity on the same terms and conditions as the utility makes those products and services available to its affiliates.

(B) **Purchase of products, services, or assets by a utility from its affiliate.** Products, services, and assets shall be priced at levels that are fair and reasonable to the customers of the utility and that reflect the market value of the product, service, or asset.

(C) **Transfers of assets.** Except for asset transfers implementing unbundling pursuant to PURA §39.051, asset valuation in accordance with PURA §39.262, and transfers of property pursuant to a financing order issued under PURA, Chapter 39, Subchapter G, assets transferred from a utility to its affiliates shall be priced at levels that are fair and reasonable to the customers of the utility and that reflect the market value of the assets or the utility's fully allocated cost to provide those assets.

(D) **Transfer of assets implementing restructuring legislation.** The transfer from a utility to an affiliate of assets implementing unbundling pursuant to PURA §39.051, asset valuation in accordance with PURA §39.262, and transfers of property pursuant to a financing order issued under PURA, Chapter 39, Subchapter G will be reviewed by the commission pursuant to the applicable provisions of PURA, and any rules implementing those provisions.

(2) **Transactions with competitive affiliates.** Unless otherwise allowed in this subsection, transactions between a utility and its competitive affiliates shall be at arm's length. A utility shall maintain a contemporaneous written record of all transactions with its competitive affiliates, except those involving corporate support services and those transactions governed by tariffs. Such records, which shall include the date of the transaction, name of affiliate involved, name of a utility employee knowledgeable about the transaction, and a description of the transaction, shall be maintained by the utility for three years. In addition to the requirements specified in paragraph (1) of this subsection, the following provisions apply to transactions between utilities and their competitive affiliates.

(A) **Provision of corporate support services**. A utility may engage in transactions directly related to the provision of corporate support services with its competitive affiliates. Such provision of corporate support services shall not allow or provide a means for the transfer of confidential information from the utility to the competitive affiliate, create the opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross- subsidization of the competitive affiliate.

(B) **Purchase of products or services by a utility from its competitive affiliate.** Except for corporate support services, a utility may not enter into a transaction to purchase a product or service from a competitive affiliate that has a per unit value of $75,000 or more, or a total value of $1 million or more, unless the transaction is the result of a fair, competitive bidding process formalized in a contract subject to the provisions of §25.273 of this title (relating to Contracts Between Electric Utilities and Their Competitive Affiliates).

(C) **Transfers of assets.** Except for asset transfers facilitating unbundling pursuant to PURA §39.051, asset valuation in accordance with PURA §39.262, and transfers of property pursuant to a financing order issued under PURA, Chapter 39, Subchapter G, any transfer from a utility to its competitive affiliates of assets with a per unit value of $75,000 or more, or a total value of $1 million or more, must be the result of a fair, competitive bidding process formalized in a contract subject to the provisions of §25.273 of this title.

(f) **Safeguards relating to provision of products and services**.

(A) **Products and services available on a non-discriminatory basis**. If a utility makes a product or service, other than corporate support services, available to a competitive affiliate, it shall make the same product or service available, contemporaneously and in the same manner, to all similarly situated entities, and it shall apply its tariffs, prices, terms, conditions, and discounts for those products and services in the same manner to all similarly situated entities. A utility shall process all requests for a product or service from competitive affiliates or similarly situated non-affiliated entities on a non-discriminatory basis. If a utility's tariff allows for discretion in its application, the utility shall apply that provision in the same manner to its competitive affiliates and similarly situated non-affiliates, as well as to their respective customers. If a utility's tariff allows no discretion in its application, the utility shall strictly apply the tariff. A utility shall not use customer-specific contracts to circumvent these requirements, nor create a product or service arrangement with its competitive affiliate that is so unique that no competitor could be similarly situated to utilize the product or service.

(B) **Discounts, rebates, fee waivers, or alternative tariff terms and conditions**. If a utility offers its competitive affiliate or grants a request from its competitive affiliate for a discount, rebate, fee waiver, or alternative tariff terms and conditions for any product or service, it must make the same benefit contemporaneously available, on a non-discriminatory basis, to all similarly situated non-affiliates. The utility shall post a conspicuous notice on its Internet site or public electronic bulletin board for at least 30 consecutive calendar days providing the following information: the name of the competitive affiliate involved in the transaction; the rate charged; the normal rate or tariff condition; the period for which the benefit applies; the quantities and the delivery points involved in the transaction (if any); any conditions or requirements applicable to the benefit; documentation of any cost differential underlying the benefit; and the procedures by which non-affiliates may obtain the same benefit. The utility shall maintain records of such information for a minimum of three years, and shall make such records available for third party review within 72 hours of a written request, or at a time mutually agreeable to the utility and the third party. A utility shall not create any arrangement with its competitive affiliate that is so unique that no competitor could be similarly situated to benefit from the discount, rebate, fee waiver, or alternative tariff terms and conditions.

(C) **Tying arrangements prohibited.** Unless otherwise allowed by the commission through a rule or tariff prior to a utility's unbundling pursuant to PURA §39.051, a utility shall not condition the provision of any product, service, pricing benefit, or alternative terms or conditions upon the purchase of any other good or service from the utility or its competitive affiliate.

(g) **Information safeguards.**

(1) **Proprietary customer information.** A utility shall provide a customer with the customer's proprietary customer information, upon request by the customer. Unless a utility obtains prior affirmative written consent or other verifiable authorization from the customer as determined by the commission, or unless otherwise permitted under this subsection, it shall not release any proprietary customer information to a competitive affiliate or any other entity, other than the customer, an independent organization as defined by PURA §39.151, or a provider of corporate support services for the sole purpose of providing corporate support services in accordance with subsection (e)(2)(A) of this section. The utility shall maintain records that include the date, time, and nature of information released when it releases customer proprietary information to another entity in accordance with this paragraph. The utility shall maintain records of such information for a minimum of three years, and shall make the records available for third party review within 72 hours of a written request, or at a time mutually agreeable to the utility and the third party. When the third party requesting review of the records is not the customer, commission, or Office of Public Utility Counsel, the records may be redacted in such a way as to protect the customer's identity. If proprietary customer information is released to an independent organization or a provider of corporate support services, the independent organization or entity providing corporate support services is subject to the rules in this subsection with respect to releasing the information to other persons.

(A) **Exception for law, regulation, or legal process.** A utility may release proprietary customer information to another entity without customer authorization where authorized or requested to do so by the commission or where required to do so by law, regulation, or legal process.

(B) **Exception for release to governmental entity.** A utility may release proprietary customer information without customer authorization to a federal, state, or local governmental entity or in connection with a court or administrative proceeding involving the customer or the utility; provided, however, that the utility shall take all reasonable actions to protect the confidentiality of such information, including, but not limited to, providing such information under a confidentiality agreement or protective order, and shall also promptly notify the affected customer in writing that such information has been requested.

(C) **Exception to facilitate transition to customer choice.** In order to facilitate the transition to customer choice, a utility may release proprietary customer information to its affiliated retail electric provider or providers of last resort without authorization of those customers only during a period prescribed by the commission.

(D) **Exception for release to providers of last resort.** On or after January 1, 2002, a utility may provide proprietary customer information to a provider of last resort without customer authorization for the purpose of serving customers who have been switched to the provider of last resort.

(E) **Exception for release to State of Texas' Division of Emergency Management.** Beginning January 1, 2011, a utility may provide proprietary customer information to the State of Texas' Division of Emergency Management, upon that agency's request for purposes of identifying the customer as a critical care residential customer pursuant to §25.497 of this title (relating to Critical Load Industrial Customers, Critical Load Public Safety Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers).

(F) **Nondiscriminatory availability of aggregate customer information.** A utility may aggregate non-proprietary customer information, including, but not limited to, information about a utility's energy purchases, sales, or operations or about a utility's energy-related goods or services. However, except in circumstances solely involving the provision of corporate support services in accordance with subsection (e)(2)(A) of this section, a utility shall aggregate non-proprietary customer information for a competitive affiliate only if the utility makes such aggregation service available to all non-affiliates under the same terms and conditions and at the same price as it is made available to any of its affiliates. In addition, no later than 24 hours prior to a utility's provision to its competitive affiliate of aggregate customer information, the utility shall post a conspicuous notice on its Internet site or other public electronic bulletin board for at least 30 consecutive calendar days, providing the following information: the name of the competitive affiliate to which the information will be provided, the rate charged for the information, a meaningful description of the information provided, and the procedures by which non-affiliates may obtain the same information under the same terms and conditions. The utility shall maintain records of such information for a minimum of three years, and shall make such records available for third party review within 72 hours of a written request, or at a time mutually agreeable to the utility and the third party.

(G) **No preferential access to transmission and distribution information.** A utility shall not allow preferential access by its competitive affiliates to information about its transmission and distribution systems.

(H) **Other limitations on information disclosure.** Nothing in this rule is intended to alter the specific limitations on disclosure of confidential information in the Texas Utilities Code, the Texas Government Code, Chapter 552, or the commission's substantive and procedural rules.

(I) **Other information**. Except as otherwise allowed in this subsection, a utility shall not share information, except for information required to perform allowed corporate support services, with competitive affiliates unless the utility can prove to the commission that the sharing will not compromise the public interest prior to any such sharing. Information that is publicly available, or that is unrelated in any way to utility activities, may be shared.

(h) **Safeguards relating to joint marketing and advertising.**

(1) **Joint marketing, advertising, and promotional activities.**

(A) A utility shall not:

(i) provide or acquire leads on behalf of its competitive affiliates;

(ii) solicit business or acquire information on behalf of any of its competitive affiliates;

(iii) give the appearance of speaking or acting on behalf of any of its competitive affiliates;

(iv) share market analysis reports or other proprietary or non-publicly available reports, with its competitive affiliates;

(v) represent to customers or potential customers that it can offer competitive retail services bundled with its tariffed services; or

(vi) request authorization from its customers to pass on information exclusively to its competitive affiliate.

(B) A utility shall not engage in joint marketing, advertising, or promotional activities of its products or services with those of a competitive affiliate in a manner that favors the affiliate. Such joint marketing, advertising, or promotional activities include, but are not limited to, the following activities:

(i) acting or appearing to act on behalf of a competitive affiliate in any communications and contacts with any existing or potential customers;
(ii) joint sales calls;
(iii) joint proposals, either as requests for proposals or responses to requests for proposals:
(iv) joint promotional communications or correspondence, except that a utility may allow a competitive affiliate access to customer bill advertising inserts according to the terms of a commission-approved tariff so long as access to such inserts is made available on the same terms and conditions to non-affiliates offering similar services as the competitive affiliate that uses bill inserts;
(v) joint presentation at trade shows, conferences, or other marketing events within the State of Texas; and
(vi) providing links between any of a utility's websites and social media platforms, and any of the websites and social media platforms of its competitive affiliates.

(C) At a customer's unsolicited request, a utility may participate in meetings with a competitive affiliate to discuss technical or operational subjects regarding the utility's provision of transmission or distribution services to the customer, but only in the same manner and to the same extent the utility participates in such meetings with unaffiliated electric or energy services suppliers and their customers. The utility shall not listen to, view, or otherwise participate in any way in a sales discussion between a customer and a competitive affiliate or an unaffiliated electric or energy services supplier.

(2) **Requests for specific competitive affiliate information.** If a customer or potential customer makes an unsolicited request to a utility for information specifically about any of its competitive affiliates, the utility may refer the customer or potential customer to the competitive affiliate for more information. Under this paragraph, the only information that a utility may provide to the customer or potential customer is the competitive affiliate's address and telephone number. The utility shall not transfer the customer directly to the competitive affiliate's customer service office via telephone or provide any other electronic link whereby the customer could contact the competitive affiliate through the utility. When providing the customer or potential customer information about the competitive affiliate, the utility shall not promote its competitive affiliate's products or services, nor shall it offer the customer or potential customer any opinion regarding the service of the competitive affiliate or any other service provider.

(3) **Requests for general information about products or services offered by competitive affiliates and their competitors.** If a customer or potential customer request general information from a utility about products or services provided by its competitive affiliate or its affiliate's competitors, the utility shall not promote its competitive affiliate or its affiliate's products or services, nor shall the utility offer the customer or potential customer any opinion regarding the service of the competitive affiliate or any other service provider. The utility may direct the customer or potential customer to a telephone directory or to the commission, or provide the customer with a recent list of suppliers developed and maintained by the commission, but the utility may not refer the customer or potential customer to the competitive affiliate except as provided for in paragraph (2) of this subsection.

(i) **Remedies and enforcement.**

(1) **Internal codes of conduct for the transition period.** During the transition to competition, including the period prior to and during utility unbundling pursuant to PURA §39.051, each utility shall implement an internal code of conduct consistent with the spirit and intent of PURA §39.157(d) and with the provisions of this section. Such internal codes of conduct are subject to commission review and approval in the context of a utility's unbundling plan submitted pursuant to PURA §39.051(e); however, such internal codes of conduct shall take effect, on an interim basis, on

January 10, 2000. The internal codes of conduct shall be developed in good faith by the utility based on the extent to which its affiliate relationships are known by January 10, 2000, and then updated as necessary to ensure compliance with PURA and commission rules. A utility exempt from PURA Chapter 39 pursuant to PURA §39.102(c) shall adopt an internal code of conduct that is consistent with its continued provision of bundled utility service during the period of its exemption.

(2) **Ensuring compliance for new affiliates.** A utility and a new affiliate are bound by the code of conduct immediately upon creation of the new affiliate. Upon the creation of a new affiliate, the utility shall immediately post a conspicuous notice of the new affiliate on its Internet site or other public electronic bulletin board for at least 30 consecutive calendar days. Within 30 days of creation of the new affiliate, the utility shall file an update to its internal code of conduct and compliance plan, including all changes due to the addition of the new affiliate. The utility shall ensure that any interaction with the new affiliate is in compliance with this section.

(3) **Compliance Audits.** No later than one year after the utility has unbundled pursuant to PURA §39.051, or acquires a competitive affiliate, and, at a minimum, every third year thereafter, the utility shall have an audit prepared by independent auditors that verifies that the utility is in compliance with this section. For a utility that has no competitive affiliates, the audit may consist solely of an affidavit stating that the utility has no competitive affiliates. The utility shall file the results of each said audit with the commission within one month of the audit's completion. The cost of the audits shall not be charged to utility ratepayers.

(4) **Informal complaint procedure.** A utility shall establish and file with the commission a complaint procedure for addressing alleged violations of this section. This procedure shall contain a mechanism whereby all complaints shall be placed in writing and shall be referred to a designated officer of the utility. All complaints shall contain the name of the complainant and a detailed factual report of the complaint, including all relevant dates, companies involved, employees involved, and the specific claim. The designated officer shall acknowledge receipt of the complaint in writing within five working days of receipt. The designated officer shall provide a written report communicating the results of the preliminary investigation to the complainant within thirty days after receipt of the complaint, including a description of any course of action that will be taken. In the event the utility and the complainant are unable to resolve the complaint, the complainant may file a formal complaint with the commission. The utility shall notify the complainant of his or her right to file a formal complaint with the commission, and shall provide the complainant with the commission's address and telephone number. The utility and the complainant shall make a good faith effort to resolve the complaint on an informal basis as promptly as practicable. The informal complaint process shall not be a prerequisite for filing a formal complaint with the commission, and the commission may, at any time, institute a complaint against a utility on its own motion.

(5) **Enforcement by the commission.** A violation or series or set of violations of this section that materially impairs, or is reasonably likely to materially impair, the ability of a person to compete in a competitive market shall be deemed an abuse of market power.

(A) In addition to other methods that may be available, the commission may enforce the provisions of this rule by:

(i) seeking an injunction or civil penalties to eliminate or remedy the violation or series or set of violations;

(ii) suspending, revoking, or amending a certificate or registration as authorized by PURA §39.356; or

(iii) pursuing administrative penalties under PURA, Chapter 15, Subchapter B.

(B) The imposition of one penalty under this section does not preclude the imposition of other penalties as appropriate for the violation or series or set of violations.

(C) In assessing penalties, the commission shall consider the following factors:

(i) the utility's prior history of violations;
(ii) the utility's efforts to comply with the commission's rules, including the extent to which the utility has adequately and physically separated its office, communications, accounting systems, information systems, lines of authority, and operations from its affiliates, and efforts to enforce these rules;
(iii) the nature and degree of economic benefit gained by the utility's competitive affiliate;
(iv) the damages or potential damages resulting from the violation or series or set of violations;
(v) the size of the business of the competitive affiliate involved;
(vi) the penalty's likely deterrence of future violations; and
(vii) such other factors deemed appropriate and material to the particular circumstances of the violation or series or set of violations.

(6) **No immunity from antitrust enforcement.** Nothing in these affiliate rules shall confer immunity from state or federal antitrust laws. Sanctions imposed by the commission for violations of this rule do not affect or preempt antitrust liability, but rather are in addition to any antitrust liability that may apply to the anti-competitive activity. Therefore, antitrust remedies also may be sought in federal or state court to cure anti-competitive activities.

(7) **No immunity from civil relief.** Nothing in these affiliate rules shall preclude any form of civil relief that may be available under federal or state law, including, but not limited to, filing a complaint with the commission consistent with this subsection.

(8) **Preemption.** This rule supersedes any procedures or protocols adopted by an independent organization as defined by PURA §39.151, or similar entity, that conflict with the provisions of this rule.

§25.273. Contracts Between Electric Utilities and Their Competitive Affiliates.

(a) **Purpose.** This section establishes the requirements for the implementation of contracts between utilities and their competitive affiliates resulting from a fair, competitive bidding process.

(b) **Application.**

(1) **General application.** This section applies to:

(A) electric utilities operating in the State of Texas as defined in the Public Utility Regulatory Act (PURA) §31.002(6), and transactions or activities between electric utilities and their affiliates, as defined in PURA §11.003(2); and

(B) transmission and distribution utilities operating in a qualifying power region in the State of Texas as defined in PURA §31.002(19) upon commission certification of a qualifying power region pursuant to PURA §39.152, and transactions or activities between transmission and distribution utilities and their affiliates, as defined in PURA §11.003(2).

(2) **No circumvention of the code of conduct**. An electric utility, transmission and distribution utility, or competitive affiliate shall not circumvent the provisions or the intent of PURA §39.157 or any rules implementing that section by using any affiliate to provide information, services, products, or subsidies between the electric utility, transmission and distribution utility, and a competitive affiliate.

(3) **Notice of conflicts and/or petition for waiver**. Nothing in this section is intended to affect or modify the obligation or duties relating to any rules or standards of conduct that may apply to a utility or the utility's affiliates under orders or regulations of the Federal Energy Regulatory Commission (FERC) or the Securities and Exchange Commission (SEC). A utility shall file with the commission a notice of any provision in this section that conflicts with FERC or SEC orders or regulations. A utility that is subject to statutes or regulations in any state that conflict with a provision of this section may petition the commission for a waiver of the conflicting provision on a showing of good cause.

(c) **Definitions.** Any terms defined in §25.272 of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates) have the same meanings herein.

(d) **Competitive bidding required.** A utility shall conduct competitive bidding, as required by §25.272 of this title, to procure products and services, other than corporate support services, that are offered by an competitive affiliate or to sell to any competitive affiliate assets that have a per unit value of more than $75,000, or a total value of more than $1 million. This section does not apply to transfers that facilitate unbundling under PURA §39.051 or asset valuation under PURA §39.262.

(1) **Notice**. The utility shall provide reasonable notice of any request for proposals required pursuant to this section. Such notice shall include:

(A) notice by publication in trade journals or newspapers as appropriate;

(B) notice by mail to persons who previously requested to be notified of the request for proposals; and

(C) conspicuous notice on the utility's Internet site or other public electronic bulletin board.

(2) **Independent evaluator**. The utility shall use an independent evaluator when a competitive affiliate's bid is included among the bids to be evaluated. If an independent evaluator is required, the utility shall maintain a record of communications with the independent evaluator. The independent evaluator shall identify in writing the bids that are most advantageous and warrant negotiation and contract execution, in accordance with the criteria set forth in the request for proposals. The utility retains responsibility for final selection of products or services.

(3) **Competitive bidding procedures.** The utility shall make a request for proposals available to interested persons by conspicuously posting the request on its Internet site or other public electronic bulletin board.

(A) The request for proposals must clearly set forth the eligibility and selection criteria and shall specify the weight to be given to any non-cost selection criteria.

(B) The utility shall strictly enforce the criteria specified in the request for proposals.

(4) **Evaluation of bids**. The utility or independent evaluator, as appropriate, shall evaluate each bid submitted in accordance with the criteria specified in the request for proposals. The utility or independent evaluator may not give preferential treatment or consideration to any bid.

(5) **Rejection of bids**. The utility is not required to accept a bid and may reject any or all bids in accordance with the selection criteria specified in the request for proposals.

(e) **Contracts.** A utility shall file with the commission a signed copy of any contracts entered into with a competitive affiliate as the result of the fair, competitive bidding process described in this section. A contract shall include, at a minimum, the following provisions:

(1) the effective date of the agreement and parties to the agreement;

(2) the term of the agreement;

(3) a narrative describing the products or services provided to the utility, including a list by specific service of all the affiliated companies who provide or receive these services, or a narrative describing the assets being sold by the utility to the competitive affiliate;

(4) the obligations of the parties;

(5) the price for those products, services, or assets governed by the contract; and

(6) billing and payment procedures.

§25.275. Code of Conduct for Municipally Owned Utilities and Electric Cooperatives Engaged in Competitive Activities.

(a) **Purpose**. To protect against anticompetitive practices, consistent with the provisions of the Public Utility Regulatory Act (PURA) §39.157(e) and Chapters 40 and 41, the provisions of this section establish safeguards to govern the interaction between the transmission and distribution business unit (TDBU), as defined in subsection (c) of this section, of a municipally owned utility (MOU) or electric cooperative (COOP) and its competitive affiliates, and establish specific anticompetitive standards to apply to the activities of Bundled MOU/COOPS, as defined in subsection (c) of this section. It is intended by this section that no MOU/COOP subject to this section shall engage in the following anticompetitive practices:

(1) Subsidize competitive activities directly or indirectly through rates charged for the provision of electric service;

(2) Allow discriminatory access to transmission and distribution products and services;

(3) Allow preferential access to transmission and distribution-related information;

(4) Allow unauthorized access to confidential customer information; and

(5) Allow employees performing transmission and distribution functions to provide leads to or promote the products of competitive affiliates or any persons providing competitive energy-related activities on behalf of a Bundled MOU/COOP.

(b) **Application.**

(1) **General application**. This section applies to the TDBU of a municipally owned utility or an electric cooperative (collectively referred to as MOU/COOP) operating in the State of Texas, and the transactions or activities between the TDBU and its competitive affiliates, and to an MOU/COOP that is conducting the activities of a TDBU and of a competitive affiliate on a bundled basis, provided that each of the following conditions is met:

(A) The MOU/COOP has chosen to participate in customer choice pursuant to PURA §40.051(b) or PURA §41.051(b).

(B) The competitive affiliate of an MOU/COOP or a Bundled MOU/COOP is providing electric energy at retail to consumers in Texas outside its certificated retail service area. For the purposes of this section, an MOU/COOP shall not be considered to be providing electric energy to retail consumers outside its certificated retail service area if:

(i) the MOU/COOP was serving the area prior to the date of customer choice;

(ii) after receiving notice that the MOU/COOP or its affiliate is selling electric energy at retail outside its retail service area, which identifies the service location, the MOU/COOP or its affiliate promptly investigates and thereafter takes reasonable steps to cease the provision of service outside its service area as soon as reasonably practicable; or

(iii) there is a dispute concerning the service area boundary and no commission order resolving the dispute has become final or the commission's order is subject to appeal.

(2) **Effect of unbundling on application**. Pursuant to PURA §40.055 and §41.055 it is the discretion of the governing body of the MOU/COOP to determine whether to unbundle any energy-related activities, and whether to do so structurally or functionally. The MOU/COOP shall file with the commission, in conjunction with the filing required by subsections (n)(1)(A) or (o)(3)(A) of this section, a written declaration of whether it chooses to structurally or functionally unbundle or whether it will provide services in a competitive market on a bundled basis. The written declaration may be amended from time to time but no amendment shall be effective before it is filed with the commission. The MOU/COOP shall comply with this section as follows:

(A) A structurally or functionally unbundled MOU/COOP shall comply with the provisions of this subsection, as applicable to entities of its size. Subsection (o) of this section is not applicable to a functionally or structurally unbundled MOU/COOP.

(B) A Bundled MOU/COOP shall comply with the requirements of paragraphs (5) and (7)-(9) of this subsection, subsection (n)(2)-(10), and subsection (o) of this section.

(3) **Small TDBU**. A small unbundled TDBU is subject to the following provisions of this section only:

(A) paragraphs (1) and (5)-(9) of this subsection, application;

(B) subsection (i)(4) of this section, separate books and records;

(C) subsection (j)(1) of this section, transactions with competitive affiliates; however, transactions provided for under subsection (j)(1) of this section shall be conducted at pricing levels that are fair and reasonable to the customers of the small TDBU and that reflect not less than the book value of the assets and the cost of employee time determined on the basis of aggregate percentage of time devoted by the employee to the competitive function or transmission and distribution function and do not include any discounts, rebates, fee waivers or alternative tariff terms and conditions;

(D) subsection (k)(1) of this section, tying arrangements prohibited;

(E) subsection (k)(2) of this section, products and services available on a non-discriminatory basis; and

(F) subsection (n) of this section, remedies and enforcement.

(4) **Mid-size TDBU.** A mid-size unbundled TDBU is subject to the following provisions of this section only:

(A) paragraphs (1) and (5)-(9) of this subsection, application;

(B) subsection (d) of this section, annual report of code-related activities; however, a mid-size TDBU shall report only with respect to the activities for which it is subject to regulation under this section;

(C) subsection (e) of this section, copies of contracts or agreements;

(D) subsection (f) of this section, tracking migration and sharing of employees;

(E) subsection (g) of this section, reporting deviations from the code of conduct; however, a mid-sized TDBU shall only report deviations with respect to the activities for which it is subject to regulation under this section;

(F) subsection (h) of this section, ensuring compliance for new competitive affiliates;

(G) subsection (i) of this section, separation of a TDBU from its competitive affiliates; however, sharing of employees, facilities, or other resources with competitive affiliates shall be allowed, and the safeguards shall be deemed achieved through compliance with the transactional, information transfer, and marketing and advertising standards applicable to a mid-size TDBU under subsections (j), (k), and (l) of this section;

(H) subsection (j)(1) of this section, transactions with competitive affiliates; however, transactions provided for under subsection (j)(1) of this section shall be conducted at pricing levels that are fair and reasonable to the customers of the mid-size TDBU and that reflect not less than the book value of the assets and the cost of employee time determined on the basis of aggregate percentage of time devoted by the employee to the competitive function or transmission and distribution function and do not include any discounts, rebates, fee waivers or alternative tariff terms and conditions;

(I) subsection (j)(2) of this section, records of transactions;

(J) subsection (j)(3) of this section, provision of corporate support services, except to the extent that sharing of confidential information may not practicably be avoided due to cross-functional responsibilities of employees;

(K) subsection (k)(1) of this section, tying arrangements prohibited;

(L) subsection (k)(2) of this section, products and services available on a non-discriminatory basis;

(M) subsection (l)(1) of this section, proprietary customer information;

(N) subsection (1)(2) of this section, nondiscriminatory availability of aggregate customer information. A mid-size TDBU shall make aggregate customer information available to all non-affiliates under the same terms and conditions and at the same price or fully allocated cost that it is made available to any of its competitive affiliates, but is not otherwise subject to the reporting requirements in subsection (l)(2) of this section.

(O) subsection (l)(3) of this section, no preferential access to transmission and distribution information. A mid-size TDBU shall comply with this paragraph except to the extent preferential access may not practicably be avoided due to cross-functional responsibilities of employees or other operating constraints as reasonably determined by the mid-size TDBU;

(P) instead of the restrictions in subsection (m)(2) of this section, a mid-sized TDBU may participate in joint marketing, advertising, and promotional activities with a competitive affiliate, provided that the mid-size TDBU informs the customer that the competitive energy services to which the promotional activities are directed are available from other providers as well as the mid-size TDBU and makes available to the customer upon request a copy of the most recent list of competitive energy service providers as developed and maintained by the commission;

(Q) instead of the restrictions in subsections (m)(3) and (m)(4) of this section, if a customer or potential customer of a mid-size TDBU makes an unsolicited request for distribution service, competitive service, or information relating to such services, the mid-size TDBU shall inform the customer that competitive energy-related activities are available not only from the mid-size TDBU but also from other providers. The mid-size TDBU shall make available to a customer upon request a copy of the most recent list of competitive energy service providers as developed and maintained by the commission and may make available telephone numbers and other commonly available information; and

(R) subsection (n) of this section, remedies and enforcement.

(5) **Duration of code application.** This section applies to a TDBU and a Bundled MOU/COOP, regardless of whether it is classified as large, mid-size or small, only so long as each of the conditions of paragraph (1) of this subsection continue to be met.

(6) **Report of energy system sales and declaration of code applicability.** A report of total metered electric energy (MWh) delivered through the TDBU's system for sale at retail and wholesale, for the average of the three most recent calendar years, shall be filed annually with the commission by each MOU/COOP subject to the provisions of this section. The initial report shall be filed in conjunction with subsection (n)(1) of this section. After the initial report filing, the report of energy system sales shall be filed annually by June 1, and shall encompass the period from January 1 through December 31 of the preceding year. The annual report of energy system sales shall be filed under a control number designated by the commission for each calendar year. Both the initial and annual reports of energy sales shall include a statement from the MOU/COOP affirming that it is classified as either a small, mid-size, or large TDBU.

(A) In the event that the MWhs delivered through the TDBU's system increase so that a TDBU is reclassified to a larger size, the TDBU shall notify the commission through the annual report of energy system sales. The TDBU shall have one year from the date of the reclassification to implement the applicable provisions of this section.

(B) Petition for exception to reclassification. Any TDBU may petition the commission for exception to the size determination. Upon request, if a small TDBU is reclassified as a mid-sized TDBU, the commission may consider an adjustment for growth based upon total Texas retail sales.

(7) **No circumvention of the code of conduct**. An MOU/COOP shall not circumvent the provisions of PURA §39.157(e) or this section by using any affiliate to provide information, services, products, or subsidies that would be prohibited by this section between a competitive affiliate and a TDBU. A Bundled MOU/COOP shall not circumvent the provisions of PURA §39.157(e) or this section by using any persons to provide information, services, products, or subsidies that would be prohibited by this section between persons providing transmission and distribution service on behalf of the

Bundled MOU/COOP and persons providing competitive energy-related activities on behalf of the Bundled MOU/COOP.

(8) **Good cause exception.** An MOU/COOP that is or may become subject to this section may petition the commission at any time for an exception or waiver of any provision of this section on a showing of good cause. Good cause may be demonstrated by showing that the cost or difficulty of achieving compliance outweighs the benefit to be achieved or that there are other alternative actions that are likely to produce reasonable results under the circumstances.

(9) **Notice of conflict with other regulation and petition for waiver.** Nothing in this section shall affect or modify the obligation or duties relating to any rules or standards of conduct that may apply to an MOU/COOP or its affiliates, whether competitive or noncompetitive, under orders or regulations of the Federal Energy Regulatory Commission (FERC), Securities and Exchange Commission (SEC), or shall violate PURA, Chapters 40 and 41, subchapter C. An MOU/COOP shall file with the commission a notice of any provision in this section that conflicts with FERC or SEC orders or regulations. An MOU/COOP that is subject to statutes or regulations in any state that conflict with a provision of this section may petition the commission for a waiver of the conflicting provision on a showing of good cause.

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

(1) **Affiliate** — An entity, including a business unit or division, that controls, is controlled by, or is under common control with, an MOU/COOP. Control means the power and authority to direct the management or policies of an entity through directly or indirectly owning or holding at least a 5.0% voting or ownership interest. Affiliate includes an entity determined to be an affiliate by the commission after notice and hearing based on criteria parallel to those prescribed in PURA §11.006.

(2) **Bundled MOU/COOP** — An MOU/COOP that is conducting both transmission and distribution activities and competitive energy-related activities on a bundled basis without structural or functional separation of transmission and distribution functions from competitive energy-related activities and that makes a written declaration of its status as a Bundled MOU/COOP pursuant to subsection (o)(3)(A) of this section.

(3) **Competitive affiliate** — An affiliate of an MOU/COOP that provides services or sells products at retail in a competitive energy-related market in this state, including telecommunications services to the extent those services are energy-related. An affiliate of an MOU/COOP that is selling energy only in the capacity of a provider of last resort within the scope of PURA §40.053(c) and (d) or PURA §41.053 (c) and (d) is not a competitive affiliate under this definition. The term competitive affiliate shall include both competitive divisions and competitive subsidiaries.

(4) **Competitive division (CD)** — A competitive affiliate that is organized as a division or other part of an MOU/COOP.

(5) **Competitive energy-related activities** — Services or products that are sold at retail in a competitive energy-related market in this state, including telecommunications services to the extent those services are energy-related.

(6) **Competitive subsidiary (CS)** — A competitive affiliate that is organized as a corporation or other legally distinct entity.

(7) **Confidential information** — Any information not intended for public disclosure and considered to be confidential or proprietary by persons privy to such information. Confidential information includes, but is not limited to, information relating to the interconnection of customers to an MOU/COOP's transmission or distribution systems, proprietary customer information, trade secrets, competitive information relating to internal manufacturing processes, and information about an MOU/COOP's transmission or distribution system, operations, or plans for expansion.

(8) **Corporate support services** — Services shared by a TDBU, or an affiliate created to perform corporate support services, with the MOU/COOP's affiliates of joint corporate oversight, governance,

support systems, and personnel. For a Bundled MOU/COOP, "corporate support services" includes governance, support systems, and personnel.

(A) Examples of services that may be shared, to the extent the services comply with this section, include human resources, procurement, information technology, regulatory services, administrative services, real estate services, legal services, accounting, environmental services, research and development unrelated to marketing activity and/or business development for the competitive affiliate regarding its services and products, internal audit, community relations, corporate communications, financial services, financial planning and management support, corporate services, corporate secretary, lobbying, corporate planning, and community economic development if the economic development activities are within the MOU/COOP's certificated retail service area.

(B) Examples of services that may not be shared, except as otherwise allowed under the terms of this section, include engineering, purchasing of electric transmission facilities and service, transmission and distribution system operations, and marketing.

(9) **Fully allocated cost** — The cost of a product, service, or asset based on book values for the component elements established through generally accepted accounting principles (GAAP); or alternatively, an internal transfer price based upon the actual or expected (budgeted) operating and maintenance expenses and a capital component, as appropriate, divided by the expected or actual units for the service or product produced. Such transfer prices may be set as needed but shall not be used beyond a three year period without review. The operating and maintenance expenses shall be fully loaded with applicable overheads. The capital component shall consider the original cost of the associated assets and a reasonable return. Such internal prices may include an allowance for transfers to a municipal general fund at the discretion of the municipality.

(10) **Large transmission and distribution business unit (TDBU) —** A TDBU that:

(A) delivers total metered electric energy through its system for sale at retail for the average of the three most recent calendar years greater than 6,000,000 MWh; and

(B) is otherwise subject to the provisions of this section as provided in subsection (b)(1) of this section.

(11) **Mid-size transmission and distribution business unit (TDBU) —** A TDBU that:

(A) delivers total metered electric energy through its system for sale at retail for the average of the three most recent calendar years that is less than or equal to 6,000,000 MWh and is greater than 500,000 MWh; and

(B) is otherwise subject to the provisions of this section as provided in subsection (b)(1) and (b)(4) of this section.

(12) **Municipally owned utility/electric cooperative (MOU/COOP)** — A municipally owned utility (MOU) as defined in PURA §11.003(11) or an electric cooperative (COOP) as defined in PURA §11.003(9). As used in this section, MOU/COOP does not include a competitive affiliate but does include an MOU, a COOP, or a river authority that has an affiliate relationship with a TDBU that is a division or part of the MOU/COOP.

(13) **Proprietary customer information** — Any information compiled by a TDBU on a customer in the normal course of providing electric service that makes possible the identification of any individual customer by matching such information with the customer's name, address, account number, type or classification of service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges, billing records, or any other information that the customer has expressly requested not be disclosed. Information that is redacted or organized in such a way as to make it impossible to identify the customer to whom the information relates does not constitute proprietary customer information.

(14) **Small transmission and distribution business unit (TDBU)** — A TDBU that:

(A) delivers total metered electric energy through its system for sale at retail of less than 500,000 MWh for the average of the three most recent calendar years; and

(B) is otherwise subject to the provisions of this section as provided in subsection (b)(1) and (b)(3) of this section.

(15) **Transaction** — Any interaction between a TDBU and its competitive affiliates in which a service, asset, product, property, right, or other item is transferred or received by either the TDBU or its competitive affiliates.

(16) **Transmission and distribution business unit (TDBU)** — The business unit of an MOU/COOP, whether structurally unbundled as a separate legal entity or functionally unbundled as a division, that owns or operates for compensation in this state equipment or facilities to transmit or distribute electricity at retail, except for facilities necessary to interconnect a generation facility with the transmission or distribution network, a facility not dedicated to public use, or a facility otherwise excluded from the definition of electric utility in a qualifying power region certified under PURA §39.152. TDBU does not include an MOU/COOP that owns, controls, or is an affiliate of the TDBU if the TDBU is organized as a separate corporation or other legally distinct entity. Except as specifically authorized by statute, a TDBU shall not provide competitive energy-related activities.

(d) **Annual report of code-related activities.** A report of activities related to this section shall be filed annually with the commission. Using forms approved by the commission, a TDBU shall report activities among itself and its competitive affiliates in accordance with the requirements of this section. The report shall be filed by June 1, and shall encompass the period from January 1 through December 31 of the preceding year during which the MOU/COOP was subject to this section.

(e) **Copies of contracts or agreements**. A TDBU shall reduce to writing and file with the commission copies of any contracts or agreements it has with its competitive affiliates. The filing of an earnings report does not satisfy the requirements of this section. All contracts or agreements shall be filed by June 1 of each year as attachments to the annual report of code-related activities required in subsection (d) of this section. In subsequent years, if no significant changes have been made to the contract or agreement, an amendment sheet may be filed in lieu of refiling the entire contract or agreement.

(f) **Tracking migration and sharing of employees.** An MOU/COOP shall track and document the movement between the TDBU and its competitive affiliates of all employees engaged in transmission or distribution system operations, including persons employed by the MOU/COOP who are engaged in transmission or distribution system operations on a day-to-day basis or who have knowledge of transmission or distribution system operations. An MOU/COOP shall also document the assignment of shared employees engaged in both transmission or distribution system operations and competitive energy-related activities, if any. Employee migration and sharing information shall be included in the MOU/COOP's annual report of code-related activities. For migrating employees, the tracking information shall include an identification code, the respective titles held while employed at the TDBU and the competitive affiliate, and the effective dates of the migration. For shared employees, the tracking information shall include the employees' name, job title, scope of activities, and allocation of time to transmission and distribution functions and competitive energy-related activities.

(g) **Reporting deviations from the code of conduct**. A TDBU shall report information regarding the instances in which deviations from this section were necessary to ensure public safety or system reliability pursuant to this section. The information reported shall include the nature of the circumstances involved and the date of the deviation. Within 30 days of each deviation relating to a competitive affiliate, the MOU/COOP shall report this information to the commission and shall conspicuously post the information on its Internet site or a public electronic bulletin board for 30 consecutive calendar days. Information regarding a deviation shall be summarized in the MOU/COOP's annual report of code-related activities.

(h) **Ensuring compliance for new competitive affiliates**. An MOU/COOP and a new competitive affiliate are bound by this code of conduct, to the extent applicable, immediately upon creation of the new competitive affiliate. The MOU/COOP shall post a conspicuous notice of any newly created competitive affiliates on its Internet site or a public electronic bulletin board for 30 consecutive calendar days. Additionally, the MOU/COOP shall ensure that its annual report of code-related activities reflects all changes that result from the creation of new competitive affiliates.

(i) **Separation of a TDBU from its competitive affiliates.**

(1) **Sharing of employees, officers and directors, property, equipment, computer and information systems, other resources, and corporate support services.** An MOU/COOP and its competitive affiliate may share common employees, officers and trustees/directors, property, equipment, computer and information systems, other resources, and corporate support services, if the TDBU implements safeguards that the commission determines are adequate to preclude employees of a competitive affiliate from gaining access to confidential information in a manner that would allow or provide a means to transfer confidential information from the TDBU to the competitive affiliate, create an opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross-subsidization of a competitive affiliate.

(2) **Employee transfers and temporary assignments**.

(A) An MOU/COOP shall not assign to a competitive affiliate for less than one year employees engaged in transmission or distribution system operations unless safeguards are in place to prevent transfer of confidential information. TDBU employees engaged in transmission or distribution system operations, including persons employed by a structurally unbundled service company affiliate of the TDBU who are engaged on a day-to-day basis in or have knowledge of transmission or distribution system operations and are transferred to a competitive affiliate, shall not remove or otherwise provide or use confidential information or information gained from the TDBU or affiliated service company, in a discriminatory or exclusive fashion to the benefit of the competitive affiliate or to the detriment of non-affiliated electric suppliers.

(B) Movement of employees to a competitive affiliate may be accomplished either through the employee's termination of employment with the TDBU and acceptance of employment with the CS or through a transfer to the CD as long as the transfer results in the TDBU bearing no ongoing costs associated with that employee.

(C) Transferring employees shall sign a statement indicating that they are aware of and understand the restrictions set forth in this section. The TDBU also shall post a conspicuous notice of such a transfer on its Internet site or other public electronic bulletin board within 24 hours and for at least 30 consecutive calendar days.

(D) Employees may be temporarily assigned to an affiliate or non-affiliated TDBU to assist in restoring power in the event of a major service interruption or to assist in resolving emergency situations affecting system reliability. Any such deviation shall be reported and posted on the TDBU's Internet site or other public electronic bulletin board within 24 hours and for at least 30 consecutive calendar days.

(3) **Sharing of office space.** A TDBU's office space shall be physically separate from the office space of its competitive affiliates. Physical separation is accomplished by having office space in separate buildings or, if within the same building, by a method such as having offices on separate floors or with separate access.

(4) **Separate books and records.** A TDBU shall maintain separate books of accounts and records from those of any CS. In a proceeding under subsection (n)(3) of this section, the commission may review records relating to a transaction between a TDBU and a CS. Costs of CDs, other than those costs related to corporate support services, shall be segregated by account.

(A) In accordance with generally accepted accounting principles, a TDBU shall record all transactions with its CS whether they involve direct or indirect expenses, and all transactions with CDs that relate to the transmission and distribution function.

(B) A TDBU shall prepare financial statements that are not consolidated with those of a CS.

(5) **Limitations on credit support by a TDBU for a competitive affiliate**. A TDBU and its affiliates may share credit, investment, or financing arrangements with a competitive affiliate if the TDBU implements adequate safeguards precluding employees of a competitive affiliate from gaining access to information in a manner that would allow or provide a means to transfer confidential information from the TDBU to the competitive affiliate or lead to customer confusion. Nothing in this section shall impair existing contracts, covenants, or obligations between an MOU/COOP and its lenders and holders of bonds issued on behalf of or by an MOU/COOP.

(A) MOU. In issuing debt related to competitive affiliates, an MOU shall be governed by and maintained, operated, and managed in accordance with the laws of the State of Texas, including the ordinances and resolutions authorizing the issuance of any form of indebtedness and the provisions thereof, which require that funds reasonably necessary for operation and maintenance expenses (including TDBU operation and maintenance expenses) have priority in any pledge of gross revenues of the municipally owned utility system.

(B) COOP. A COOP TDBU shall not allow a competitive affiliate to obtain credit under any arrangement that would include a specific pledge of assets reasonably necessary for TDBU operations or a pledge of gross revenues of the TDBU.

(j) **Transactions between a TDBU and its competitive affiliates**.

(1) **Transactions with competitive affiliates**. Except for transfers implementing unbundling, transfers of property pursuant to a rate order having the effect of a financing order, credit support, and corporate support services provided by a TDBU to its competitive affiliate, any transaction between a TDBU and its competitive affiliate shall be accomplished at pricing levels that are fair and reasonable to the customers of the TDBU and that reflect the approximate market value of the assets or the fully allocated cost of the assets, services, or products, and that do not include any preferential discounts, rebates, fee waivers or alternative tariff terms and conditions. Such transfers include, but are not limited to, the following:

(A) sale or provision of products or services by a TDBU to its competitive affiliate;

(B) purchase or acquisition of products, services, or assets by a TDBU from a competitive affiliate; or

(C) assets transferred from a TDBU to a competitive affiliate.

(2) **Records of transactions.** Each transaction between a TDBU and its competitive affiliates, other than those involving corporate support services or transactions governed by tariffs of general applicability filed at the commission or approved by the TDBU's governing body, shall be reflected in a contemporaneous written record of the transaction including the date of the transaction, name of the competitive affiliate, name of a TDBU employee knowledgeable about the transaction, and description of the transaction. Such records shall be maintained for three years.

(3) **Provision of corporate support services**. A TDBU may engage in transactions directly related to the provision of corporate support services with its competitive affiliate. Such transactions shall be carried out in such a way as to not allow or provide the means for the transfer of confidential information from the TDBU to the competitive affiliate, the opportunity for preferential treatment or unfair competitive advantage, customer confusion, or significant opportunities for cross-subsidization of the competitive affiliate.

(k) **Safeguards relating to provision of products and services.**

(1) **Tying arrangements prohibited.** A TDBU shall not condition the provision of any product, service, pricing benefit, or alternative terms or conditions upon the purchase of any other good or service from the TDBU or its competitive affiliate.

(2) **Products and services available on a non-discriminatory basis.** Any product or service, other than corporate support services or credit arrangements, made available by a TDBU to its competitive affiliate shall be made available to all similarly situated entities at the same price and on the same basis and manner that the product or service was made available to the competitive affiliate, provided however, that such provision does not violate PURA §40.104 or §41.104, or the Texas Constitution, Article III, section 52. Any service required to be provided in compliance with PURA §39.203 shall be provided in a non-discriminatory manner and in accordance with the tariffs developed pursuant to any commission rule implementing that section.

(l) **Information safeguards**.

(1) **Proprietary customer information**. Upon request by the customer, a TDBU shall provide a customer with the customer's proprietary customer information. Unless a TDBU obtains prior affirmative written consent or other verifiable authorization from the customer as determined by the commission, or unless otherwise permitted under this subsection, it shall not release any proprietary customer information to a competitive affiliate or to any other entity, other than the customer, an independent organization as defined by PURA §39.151, or a provider of corporate support services for the sole purpose of providing corporate support services in accordance with subsection (j)(3) of this section. The TDBU shall maintain records that include the date, time, and nature of information released when it releases customer proprietary information to another entity in accordance with this paragraph. The TDBU shall maintain records of such information for a minimum of three years and shall make the records available for third party review within three business days of a written request or at a time mutually agreeable to the TDBU and the third party. When the third party requesting review of the records is not the customer, commission, or Office of Public Utility Counsel, the records may be redacted in such a way as to protect the customer's identity. If proprietary customer information is released to an independent organization or a provider of corporate support services, the independent organization or entity providing corporate support services is subject to the rules in this subsection with respect to releasing the information to other persons.

(A) Exception for law, regulation, or legal process. A TDBU may release proprietary customer information to another entity without customer authorization where authorized or requested to do so by the commission or by law, regulation, or legal process. Nothing in this rule requires disclosure of information that may be withheld from disclosure under Texas Government Code, Chapter 552.

(B) Exception for release to governmental entity. Without customer authorization, a TDBU may release proprietary customer information to a federal, state, or local governmental entity or in connection with a court or administrative proceeding involving the customer or the TDBU, provided however, that the TDBU shall take all reasonable actions to protect the confidentiality of such information, including, but not limited to, providing such information under a confidentiality agreement or protective order, and shall also promptly notify the affected customer in writing that such information has been requested.

(C) Exception to facilitate transition to customer choice. In order to facilitate the transition to customer choice, an MOU/COOP may release proprietary customer information to its competitive affiliate without authorization of those customers, where either entity will be exercising the function of retail electric provider or provider of last resort, provided however, that such information may be released only during the six-month period prior to implementation of customer choice, during the six-month period prior to implementation or expansion of a pilot project, or such additional periods as may be prescribed by the commission.

(D) Exception for release to providers of last resort. On or after January 1, 2002, a TDBU may provide proprietary customer information to a provider of last resort without customer authorization for the purpose of serving customers who have been switched to the provider of last resort.

(E) Exception for release to customer's selected competitive retailer. Subject to demonstration by the competitive retailer that the customer has selected that competitive retailer, a TDBU shall release proprietary customer information for a particular customer to the competitive retailer chosen by that customer in connection with provision of metering data or otherwise in compliance with the Access Tariff applicable to the TDBU under PURA §39.203.

(2) **Nondiscriminatory availability of aggregate customer information.** A TDBU may aggregate non-proprietary customer information, including, but not limited to, information about a TDBU's energy-related goods or services. However, except in circumstances solely involving the provision of corporate support services in accordance with subsection (j)(3) of this section, a TDBU shall aggregate non-proprietary customer information for a competitive affiliate only if the TDBU makes such aggregation service available to all non-affiliates under the same terms and conditions and at the same price or fully allocated cost as it is made available to any of its competitive affiliates. In addition, no later than 24 hours prior to a TDBU's provision to its competitive affiliate of aggregate customer information, the TDBU shall post a conspicuous notice on its Internet site or other public electronic bulletin board for at least 30 consecutive calendar days, providing the following information: the name of the competitive affiliate to which the information will be provided, the rate charged or cost allocated for the information, a meaningful description of the information provided, and the procedures by which non-affiliates may obtain the same information under the terms and conditions. The TDBU shall maintain records of such disclosure information for a minimum of three years and shall make such records available for third party review within three business days of a written request or at a time mutually agreeable to the TDBU and the third party.

(3) **No preferential access to transmission and distribution information.** A TDBU shall not allow preferential access by its competitive affiliates to information about its transmission and distribution systems.

(4) **Other limitations on information disclosure.** Nothing in this rule is intended to alter the specific limitations on disclosure of confidential information in the Texas Utilities Code, the Texas Government Code, Chapter 552, or the commission's substantive and procedural rules.

(5) **Other information.** Except as otherwise allowed in this subsection, a TDBU shall not share information with competitive affiliates, except for information required to perform allowed corporate support services unless the TDBU can prove to the commission that the sharing will not compromise the public interest prior to any such sharing. Information that is publicly available, or that is unrelated in any way to utility activities, may be shared.

(m) **Safeguards relating to joint marketing and advertising.**

(1) **Name and logo.** A TDBU may not, prior to September 1, 2005, allow the use of its corporate trademark, name, brand, or logo by a CS on employee business cards or in any written or auditory advertisements of specific services to existing or potential residential or small commercial customers located within the TDBU's certificated service area, whether through radio or television, Internet-based, or other electronic format accessible to the public unless the CS includes a disclaimer with its use of the TDBU's corporate trademark, name, brand, or logo. Such disclaimer of the corporate trademark, name, brand, or logo in the material distributed must be written in a bold and conspicuous manner or clearly audible, as appropriate for the communication medium, and shall state the following: "{Name of CS} is not the same entity as {name of TDBU} and you do not have to buy {name of CS}'s products to continue to receive quality services from {name of TDBU}." A TDBU may allow the use of its corporate name, brand, or logo by a CD in any context.

(2) **Joint marketing, advertising, and promotional activities.**

(A) A TDBU shall not:

(i) provide or acquire leads on behalf of its competitive affiliates;

(ii) solicit business or acquire information on behalf of its competitive affiliates;

(iii) give the appearance of speaking or acting on behalf of any of its competitive affiliates in connection with any marketing, advertising or promotional activities, other than community economic development activities;

(iv) share market analysis reports or other types of proprietary or non-publicly available reports relating to retail energy sales, including, but not limited to, market forecast, planning, or strategic reports with its competitive affiliates; or

(v) request authorization from its customers to pass on information exclusively to its competitive affiliate.

(B) A TDBU shall not engage in joint marketing, advertising, or promotional activities of its products or services with those of a competitive affiliate in a manner that favors the competitive affiliate. Such joint marketing, advertising, or promotional activities include, but are not limited to, the following activities:

(i) acting or appearing to act on behalf of a competitive affiliate in any communications and contacts with any existing or potential customers;

(ii) joint sales calls;

(iii) joint proposals, either as requests for proposals or responses to requests for proposals;

(iv) joint promotional communications or correspondence, except that a TDBU may allow a competitive affiliate access to customer bill advertising inserts so long as access to such inserts is made available on the same terms and conditions to non-affiliates offering similar services as the competitive affiliate that uses bill inserts;

(v) joint presentations at trade shows, conferences, or other marketing events within the state of Texas; and

(vi) providing links from a TDBU's Internet web site to a competitive affiliate's Internet web site.

(C) At a customer's unsolicited request, a TDBU may participate in meetings with a competitive affiliate to discuss technical or operational subjects regarding the TDBU's provision of transmission or distribution services to the customer but only in the same manner and to the same extent the TDBU participates in such meetings with unaffiliated electric or energy services suppliers and their customers. Representatives of a TDBU may be present during a sales discussion between a customer and the TDBU's competitive affiliate but shall not participate in the discussion or purport to act on behalf of the competitive affiliate.

(3) **Requests for specific competitive affiliate information**. If a customer or potential customer makes an unsolicited request to a TDBU for information specifically about any of its competitive affiliates, the TDBU may refer the customer or potential customer to the competitive affiliate for more information. Under this paragraph, the only information that a TDBU may provide to the customer or potential customer is the competitive affiliate's address and telephone number. The TDBU shall not transfer the customer directly to the competitive affiliate's customer service office via telephone or provide any other electronic link whereby the customer could contact the competitive affiliate through the TDBU. When providing the customer or potential customer information about the competitive affiliate, the TDBU shall not promote its competitive affiliate or its competitive affiliate's products or services, nor shall it offer the customer or potential customer any opinion regarding the service of the competitive affiliate or any other service provider.

(4) **Requests for general information about products or services offered by competitive affiliates and their competitors**. If a customer or potential customer requests general information from a TDBU about products or services provided by its competitive affiliate or the competitors of its CS or CD, the TDBU shall not promote its competitive affiliate or its competitive affiliate's products or services, nor shall the TDBU offer the customer or potential customer any opinion regarding the

service of the competitive affiliate or any other service provider. The TDBU may direct the customer or potential customer to a telephone directory or to the commission, or provide the customer with a recent list of suppliers developed and maintained by the commission, but the TDBU may not refer the customer or potential customer to the competitive affiliate except as provided for in paragraph (3) of this subsection.

(n) **Remedies and enforcement.**

(1) **Code implementation filing.**

(A) Not later than 120 days prior to the implementation of customer choice by an MOU/COOP, a TDBU shall file with the commission its plan for implementing the provisions of this section, addressing all applicable requirements of this section in the context of its operations as they will be conducted in the competitive retail market. The TDBU shall post notice of its filing on its Internet site or a public electronic bulletin board for 30 consecutive days and shall provide copies of the filing to requesting parties. Interested parties may file comments on the filing with the commission within 30 days following the filing and shall provide copies of such comments to the TDBU. Commission staff shall review the code implementation filing and provide to the TDBU its comments and recommendations as to any suggested changes in the filing within 60 days following the date of the filing. The TDBU may amend its initial filing based on the comments and recommendations and shall file any such amendments not later than 75 days following the date of the initial filing. The filing provided for in this paragraph is not subject to the contested hearings process, except upon complaint by an interested party or the commission staff.

(B) In lieu of the implementation filing provided for in subparagraph (A) of this paragraph, an MOU/COOP may file with the commission a statement that it does not at this time intend to provide electric energy at retail to consumers in Texas outside its certificated retail service area as provided for in subsection (b)(1)(B) of this section. Subsequently, if an MOU/COOP intends to provide electric energy at retail to consumers in Texas outside its certificated retail service area as provided for in subsection (b)(1)(B) of this section, it shall file with the commission the implementation filing provided for in subparagraph (A) of this paragraph not later than 120 days prior to the time it provides retail electric energy in Texas outside its certificated retail service area.

(2) **Informal complaint procedure.** A TDBU or a Bundled MOU/COOP shall establish and file with the commission a complaint procedure for addressing alleged violations of this section. This procedure shall contain a mechanism whereby all complaints shall be placed in writing and shall be referred to a designated officer or other person employed by the TDBU or the Bundled MOU/COOP.

(A) All complaints shall contain:

(i) the name of the complainant;

(ii) a detailed factual report of the complaint, including all relevant dates, entities or divisions involved, employees involved, and the specific claim.

(B) A complaint must be filed with the TDBU or the Bundled MOU/COOP within 90 days of the date the complaining party knew, or with diligent investigation should have known, that the violation occurred, but in no event may a complaint be filed more than three years after the violation occurred.

(C) The designated officer shall acknowledge receipt of the complaint in writing within five working days of receipt. The designated officer shall provide a written report communicating the results of the preliminary investigation to the complainant within 30 days after receipt of the complaint, including a description of any course of action that will be taken.

(D) In the event the TDBU or the Bundled MOU/COOP and the complainant are unable to resolve the complaint, the complainant may file a formal complaint with the commission. In the event the complainant advises the TDBU or the Bundled MOU/COOP that the complainant does not consider the complaint fully resolved by the course of action proposed by the TDBU or the Bundled MOU/COOP then the TDBU or the Bundled MOU/COOP shall notify the complainant of his or her right to file a formal complaint with the commission and shall provide the complainant with the commission's address and telephone number. The informal complaint process shall be a prerequisite for filing a formal complaint with the commission.

(E) A large TDBU or Bundled MOU/COOP shall report to the commission regarding the nature and status of informal complaints handled in accordance with this paragraph in its annual report of code-related activities filed pursuant to subsection (d) of this section. The information reported to the commission shall include the name of the complainant and a summary report of the complaint, including all relevant dates, companies involved, employees involved, the specific claim, and any actions taken to address the complaint. Such information on all informal complaints that were initiated or remained unresolved during the reporting period shall be included in the annual report of code-related activities of the large TDBU or Bundled MOU/COOP.

(3) **Filing a complaint.** Following the informal process, a formal complaint may be filed with the commission alleging a violation of this section. No complaint shall be valid unless filed with the commission within 30 days after the designated officer or employee of the TDBU or the Bundled MOU/COOP mails its written report communicating the results of the preliminary investigation to the complainant. Each complaint shall contain the name of the complainant and a detailed factual report of the complaint, including all relevant dates, entities or divisions involved, employees involved, and the specific claim. Additionally, each complaint shall identify the specific provisions of this section that are alleged to have been violated, contain a sworn affidavit that the facts alleged are true and correct to the best of the affiant's knowledge and belief, and if the complainant is a corporation, a statement from a corporate officer that he or she is authorized to file the complaint.

(4) **Notification of complaint and opportunity to respond**. The commission shall provide a copy of the complaint to the TDBU or the Bundled MOU/COOP. The TDBU or the Bundled MOU/COOP shall respond to the complaint in writing within 15 days. The TDBU or the Bundled MOU/COOP and the complainant shall make a good faith effort to resolve the complaint on an informal basis as promptly as practicable.

(5) **Settlement conference**. Upon request by the MOU/COOP subject to the complaint, commission staff shall conduct a settlement conference. At such settlement conference, each party, including the commission staff, shall recommend what steps are necessary to cure any violation that it believes has occurred. Discussions at the settlement conference, including the recommendations to cure the violation, shall not be admissible at a hearing on the complaint.

(6) **Opportunity to cure.** The MOU/COOP shall have three months to cure the violation in accordance with an agreement arising from the settlement conference or following a hearing. An MOU/COOP may cure the violation in any reasonable manner as set forth in the settlement agreement or hearing, including taking action designed to prevent recurrence of the violation or amending the rule or order.

(7) **Enforcement by the commission.** In the event the commission finds there has been a violation which has not been reasonably cured, the commission may enforce the provisions of this section.

(A) The commission may recommend actions to be taken by the MOU/COOP within a prescribed time, and if such actions are not taken, the commission may:

(i) seek an injunction to eliminate or remedy the violation or series or set of violations; or

(ii) limit or prohibit retail service outside the certificated retail service area of the TDBU or the Bundled MOU/COOP until the violation or violations are adequately remedied. This remedy shall not be applied in a manner that would interfere with or abrogate the rights or obligations of parties to a lawful contract.

(B) In assessing enforcement remedies, the commission shall consider the following factors:

(i) the prior history of violations by the TDBU or the Bundled MOU/COOP, if any, found by the commission after hearing;

(ii) the efforts made by the TDBU or the Bundled MOU/COOP to comply with the commission's rules;

(iii) the nature and extent of economic benefit gained by the TDBU's competitive affiliate or the Bundled MOU/COOP;

(iv) the damages or potential damages resulting from the violation or series or set of violations;

(v) the size of the business of the competitive affiliate involved; and

(vi) such other factors deemed appropriate and material to the particular circumstances of the violation or series or set of violations.

(C) The commission may conduct a compliance audit of affiliate activities to ensure compliance with the code of conduct.

(8) **No immunity from antitrust enforcement.** Nothing in these affiliate rules shall confer immunity from state or federal antitrust laws. Enforcement actions by the commission for violations of this section do not affect or preempt antitrust liability, but rather are in addition to any antitrust liability that may apply to the anti-competitive activity. Therefore, antitrust remedies may also be sought in federal or state court to cure anti-competitive activities.

(9) **No immunity from civil relief.** Nothing in these affiliate rules shall preclude any form of civil relief that may be available under federal or state law, including, but not limited to, filing a complaint with the commission consistent with this subsection.

(10) **Preemption.** This section supersedes any procedures or protocols adopted by an independent organization as defined by PURA §39.151, or similar entity, that conflict with the provisions of this section.

(o) **Provisions for Bundled MOU/COOPs.**

(1) **Transactional safeguards relating to provision of products and services.** To protect against anticompetitive activities, the provisions of this subsection apply to all Bundled MOU/COOPs meeting the qualifications set forth in subsection (b)(1)(A) and (B) of this section, regardless of whether the MOU/COOP has any affiliates or competitive affiliates.

(A) Tying arrangements prohibited. A Bundled MOU/COOP shall not condition the provision of any transmission or distribution product, service, pricing benefit, or alternative terms or conditions upon the purchase of any other good or service from the Bundled MOU/COOP.

(B) Products and services available on a non-discriminatory basis. Any product or service, other than corporate support services or credit arrangements, made available by a Bundled MOU/COOP to any third party or any persons providing competitive energy-related activities on behalf of the Bundled MOU/COOP, shall be made available to all similarly situated entities at the same price and on the same basis and manner that the product or service was made available to any persons providing competitive energy-related activities on behalf of the Bundled MOU/COOP, provided however, that such provision does not violate PURA §40.104 or §41.104, or the Texas Constitution, Article III, section 52. Any service required to be provided in compliance with PURA §39.203 shall be provided in a non-discriminatory manner and in accordance with the tariffs developed pursuant to any commission rule implementing that section.

(C) Cross-subsidization prohibited. A Bundled MOU/COOP shall not create significant opportunities for cross subsidization of competitive energy-related activities with revenues from distribution and transmission rates.

(D) Records of transactions involving competitive energy-related activities. A Bundled MOU/COOP shall maintain segregated accounts and records of all transactions regarding the provision of competitive energy-related activities consistent with the FERC chart of accounts or a comparable tracking method. In accordance with generally accepted accounting principles, a Bundled MOU/COOP shall separately record all transactions regarding the provision of competitive energy-related activities and all transactions relating to the transmission and distribution function. Such records shall include all expenses, whether direct or indirect, and at the fully allocated cost to provide such competitive energy service. Such expenses shall not be included in the Bundled MOU/COOP's transmission and distribution rates.

(E) Transfer or use of assets or products to provide competitive energy-related activities. A Bundled MOU/COOP shall implement procedures and safeguards to ensure that the transfer or use of assets or products by a person providing competitive energy-related activities on behalf of the Bundled MOU/COOP shall be accomplished at pricing levels that are fair and reasonable to the customers of the transmission and distribution system of the Bundled MOU/COOP and at pricing levels that do not include any preferential discounts, rebates, fee waivers or alternative tariff terms and conditions.

(F) Provision of corporate support services. The provision of corporate support services by a Bundled MOU/COOP to provide competitive energy-related activities shall be carried out in such a way as to comply with the provisions of paragraph (2)(A)-(D) of this subsection, thereby preventing the opportunity for preferential treatment or unfair competitive advantage, customer confusion, or significant opportunities for cross-subsidization.

(G) No preferential access to transmission and distribution information. A Bundled MOU/COOP shall not allow preferential access by any person providing competitive energy-related activities on behalf of the Bundled MOU/COOP to information about its transmission and distribution systems. Such information shall be provided as required in paragraph (2)(D) of this subsection.

(H) Sharing of personnel, facilities, and resources. A Bundled MOU/COOP shall implement procedures and safeguards governing the sharing of personnel, facilities, officers and directors, equipment, and corporate support services with persons providing competitive energy-related activities on behalf of the Bundled MOU/COOP to ensure that confidential information is protected, that there are no opportunities for preferential treatment or unfair competitive advantage, that undue customer confusion will be prevented, and that no significant opportunities for cross-subsidization are created. A Bundled MOU/COOP shall document the assignment of shared employees engaged in both transmission or distribution system operations and the provision of competitive energy-related activities. For shared employees, the tracking documentation shall include the employees' name, job title, scope of activities, and allocation of time to the transmission and distributions functions and competitive energy-related activities. The tracking documentation for shared employees shall be filed annually with the annual report of code-related activities required by paragraph (3)(B) of this subsection.

(I) Marketing and advertising. A Bundled MOU/COOP shall implement procedures and safeguards relating to the marketing and advertising of the Bundled MOU/COOP's competitive energy-related activities to prevent favoritism being shown to the competitive energy-related activities provided by the Bundled MOU/COOP, to prevent customer confusion, to prevent the inappropriate sharing of customer information, and to prevent significant opportunities for cross-subsidization.

(2) **Informational safeguards.** The following provisions apply to Bundled MOU/COOPs.

(A) Sharing of customer information. A Bundled MOU/COOP shall implement adequate safeguards to preclude any persons providing competitive energy-related activities on behalf of the Bundled MOU/COOP, or any other entities, from gaining access to information in a manner that would allow or provide a means to transfer confidential information, create an opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross-subsidization. Non-proprietary information possessed by the Bundled MOU/COOP that is made available to any persons providing competitive energy-related activities provided by the Bundled MOU/COOP shall likewise be made available to third parties providing competitive energy-related activities at the Bundled MOU/COOP's cost to produce such information for the third party.

(B) Proprietary customer information. Upon request by the customer, a Bundled MOU/COOP shall provide a customer with the customer's proprietary customer information. Unless a Bundled MOU/COOP obtains prior affirmative written consent or other verifiable authorization from the customer as determined by the commission, or unless otherwise permitted under this subparagraph, it shall not release any proprietary customer information to a person providing competitive energy-related activities on behalf of the Bundled MOU/COOP or to any other entity, other than the customer, an independent organization as defined by PURA §39.151, or a provider of corporate support services for the sole purpose of providing corporate support services. The Bundled MOU/COOP shall be permitted to release proprietary customer information under the same terms and conditions as a TDBU as set forth in subsections (l)(1)(A)-(E) of this section.

(C) Nondiscriminatory availability of aggregate customer information. A Bundled MOU/COOP may aggregate non-proprietary customer information, including, but not limited to, information about a Bundled MOU/COOP's energy-related goods or services. However, except in circumstances solely involving the provision of corporate support services, a Bundled MOU/COOP shall aggregate non-proprietary customer information for a third party or any person providing competitive energy-related activities only if the Bundled MOU/COOP makes such aggregation service available to all non-affiliates and third parties under the same terms and conditions and at the same price or fully allocated cost as it is made available to any person providing competitive energy-related activities on behalf of the Bundled MOU/COOP.

(D) Requests for information. If a customer or potential customer of a Bundled MOU/COOP makes an unsolicited request for distribution service, competitive energy-related activities, products or services provided by an Bundled MOU/COOP, or for information relating to such products or services, the Bundled MOU/COOP shall inform the customer that competitive energy-related activities are available not only from the Bundled MOU/COOP, but also from other providers. If the Bundled MOU/COOP provides the customer or potential customer with information about competitive energy-related activities offered by the Bundled MOU/COOP, the Bundled MOU/COOP must record and allocate the costs associated with the provision of such information in the same manner as transactions involving the provision of competitive energy related activities, in accordance with paragraph (1)(C) of this subsection. The Bundled MOU/COOP shall not offer the customer or potential customer any opinion regarding the service of any other competitive energy service provider. Upon request, the Bundled MOU/COOP shall make available to a customer a copy of the most recent list of competitive energy service providers as developed and maintained by the commission and may make available telephone numbers and other commonly available information. Such information shall also be made available by the Bundled MOU/COOP to its transmission and distribution customers at the time the Bundled MOU/COOP undertakes marketing to those customers of its competitive energy-related activities.

(3) **Reporting and auditing requirements.** A Bundled MOU/COOP shall maintain and file the following information so the commission can ensure that the Bundled MOU/COOP is not engaging in any anticompetitive activities as a result of its competitive energy-related activities being bundled with the transmission and distribution operation.

(A) Code implementation filing.

(i) Not later than 120 days prior to the implementation of customer choice by a Bundled MOU/COOP, the Bundled MOU/COOP shall file with the commission a written declaration that it will operate as a Bundled MOU/COOP and its plan for implementing the provisions of this section. The plan shall address all applicable requirements of this section in the context of operations as they will be conducted in the competitive retail market. The Bundled MOU/COOP shall post notice of its filing on its Internet site or a public electronic bulletin board for 30 consecutive days and shall provide copies of the plan to requesting parties. The code implementation plan proposed by the Bundled MOU/COOP shall be subject to a contested hearing process. Interested parties may file comments on the filing with the commission. The commission shall issue an order either approving the code implementation plan, approving the plan with modifications, or rejecting the plan within 120 days.

(ii) In lieu of the implementation filing provided for in clause (i) of this subparagraph, a Bundled MOU/COOP may file with the commission a statement that it does not at this time intend to provide electric energy at retail to customers in Texas outside its certificated retail service area as provided for in subsection (b)(1)(B) of this section. Subsequently, if a Bundled MOU/COOP intends to provide electric energy at retail to consumers in Texas outside its certificated retail service area as provided for in subsection (b)(1)(B) of this section, it shall file the implementation filing provided for in clause (i) of this subparagraph with the commission not later than 120 days prior to the time it intends to provide retail electric energy in Texas outside its certificated retail service area.

(B) Annual report of code-related activities. A report of activities related to this subsection shall be filed annually with the commission under a control number designated by the commission. The report shall be filed by June 1 and shall encompass the period from January 1 through December 31 of the preceding year. The report shall contain detailed information on how the Bundled MOU/COOP met each of the provisions of paragraphs (1) and (2) of this subsection and any deviations from the actions set forth in the initial code compliance filing. Commission staff shall review the annual report of code-related activities. The filing provided for in this paragraph is not subject to the contested hearings process, except upon complaint by an interested party or the commission staff.

(C) Copies of contracts or agreements. A Bundled MOU/COOP shall reduce to writing and file with the commission copies of any contracts or agreements it has with any persons providing competitive energy-related activities on behalf of the Bundled MOU/COOP. The Bundled MOU/COOP does not have to produce any contracts it has with third parties if such contracts were negotiated on an arm's length basis. The requirements of this section are not satisfied by the filing of an earnings report. All contracts or agreements shall be filed by June 1 of each year as attachments to the annual report of code-related activities required in subparagraph (B) of this paragraph. In subsequent years, if no significant changes have been made to the contract or agreement, an amendment sheet may be filed in lieu of refiling the entire contract or agreement.

(D) Compliance audits. No later than one year after the Bundled MOU/COOP becomes subject to this section as set forth in subsection (b)(1) and (2) of this section, and, at a minimum, every third year thereafter, the Bundled MOU/COOP shall have an audit prepared by independent auditors that verifies that the Bundled MOU/COOP is in compliance with this section. The Bundled MOU/COOP shall file the results of each audit with the commission within one month of the audit's completion.

(4) **Remedies and enforcement.** Bundled MOU/COOPs shall be subject to the provisions of subsection (n)(2)-(10) of this section on the same terms and conditions as the TDBU.

§25.301. Nuclear Decommissioning Trusts.

(a) **Duties of electric utilities.**

(1) Each electric utility collecting funds for a nuclear decommissioning trust shall assure that the nuclear decommissioning trust is managed so that the funds are secure and earn a reasonable return; and, that the funds provided from the utility's cost of service, plus the amounts earned from investment of the funds, will be available at the time of decommissioning.

(2) Each electric utility collecting funds for a nuclear decommissioning trust shall place the funds in an external, irrevocable trust fund. The utility shall appoint an institutional trustee and may appoint an investment manager(s). Unless otherwise specified in subsection (b) of this section, the Texas Trust Code controls the administration and management of the nuclear decommissioning trusts, except that the appointed trustee(s) need not be qualified to exercise trust powers in Texas.

(3) The utility shall retain the right to replace the trustee with or without cause. In appointing a trustee, the electric utility shall have the following duties, which will be of a continuing nature:

(A) A duty to determine whether the trustee's fee schedule for administering the trust is reasonable, when compared to other institutional trustees rendering similar services, and meets the requirement of subsection (c)(2)(A) of this section;

(B) A duty to investigate and determine whether the past administration of trusts by the trustee has been reasonable;

(C) A duty to investigate and determine whether the financial stability and strength of the trustee is adequate;

(D) A duty to investigate and determine whether the trustee has complied with the trust agreement and this section as it relates to trustees; and,

(E) A duty to investigate any other factors which may bear on whether the trustee is suitable.

(4) The utility shall retain the right to replace the investment manager with or without cause. In appointing an investment manager, the utility shall have the following duties, which will be of a continuing nature:

(A) A duty to determine whether the investment manager's fee schedule for investment management services is reasonable, when compared to other such managers, and meets the requirement of subsection (c)(2)(A) of this section;

(B) A duty to investigate and determine whether the past performance of the investment manager in managing investments has been reasonable;

(C) A duty to investigate and determine whether the financial stability and strength of the investment manager is adequate for purposes of liability;

(D) A duty to investigate and determine whether the investment manager has complied with the investment management agreement and this section as it relates to investments; and,

(E) A duty to investigate any other factors which may bear on whether the investment manager is suitable.

(b) **Agreements between the electric utility and the institutional trustee or investment manager.**

(1) The utility shall execute an agreement with the institutional trustee. The agreement shall include the restrictions in subparagraphs (A) - (E) of this paragraph and may include additional restrictions on the trustee. An electric utility shall not grant the trustee powers that are greater than those provided to trustees under the Texas Trust Code or that are inconsistent with the limitations of this section.

(A) The interest earned on the corpus of the trust becomes part of the trust corpus. A trustee owes the same duties with regard to the interest earned on the corpus as are owed with regard to the corpus of the trust.

(B) A trustee shall have a continuing duty to review the trust portfolio for compliance with investment guidelines and governing regulations.

(C) A trustee shall not lend funds from the decommissioning trust with itself, its officers, or its directors.

(D) A trustee shall not invest or reinvest decommissioning trust funds in instruments issued by the trustee, except for time deposits, demand deposits, or money market accounts of the trustee. However, investments of a decommissioning trust may include mutual funds that contain securities issued by the trustee if the securities of the trustee constitute no more than five percent of the fair market value of the assets of such mutual funds at the time of the investment.

(E) The agreement shall comply with all applicable requirements of the Nuclear Regulatory Commission.

(2) The utility shall execute an agreement with the investment manager. (If the trustee performs investment management functions, the contractual provisions governing those functions must be included in either the trust agreement or a separate investment management agreement.) The agreement shall include the restrictions set forth in subparagraphs (A) - (E) of this paragraph and may include additional restrictions on the manager. An electric utility shall not grant the manager powers that are greater than those provided to trustees under the Texas Trust Code or that are inconsistent with the limitations of this section.

(A) An investment manager shall, in investing and reinvesting the funds in the trust, comply with subsection (c) of this section.

(B) The interest earned on the corpus of the trust becomes part of the trust corpus. An investment manager owes the same duties with regard to the interest earned on the corpus as are owed with regard to the corpus of the trust.

(C) An investment manager shall have a continuing duty to review the trust portfolio to determine the appropriateness of the investments.

(D) An investment manager shall not invest funds from the decommissioning trust with itself, its officers, or its directors.

(E) The agreement shall comply with all applicable requirements of the Nuclear Regulatory Commission.

(3) A copy of the trust agreement, any investment management agreement, and any amendments shall be filed with the commission within 30 days after the execution or modification of the agreement, and copies provided to the commission's Office of Regulatory Affairs' Legal Division and Financial Review Division and the Office of Public Utility Counsel. All previously executed agreements and amendments must be filed within 30 days of the effective date of this section.

(4) Within 90 days after the effective date of this section, a utility that is a party to a trust agreement or an investment management agreement that is not in compliance with this section shall revise the agreement to comply with this section.

(c) **Trust investments.**

(1) **Investment portfolio goals.** The funds should be invested consistent with the following goals. The utility may apply additional prudent investment goals to the funds so long as they are not inconsistent with the stated goals of this subsection.

(A) The funds should be invested with a goal of earning a reasonable return commensurate with the need to preserve the value of the assets of the trusts.

(B) In keeping with prudent investment practices, the portfolio of securities held in the decommissioning trust shall be diversified to the extent reasonably feasible given the size of the trust.

(C) Asset allocation and the acceptable risk level of the portfolio should take into account market conditions, the time horizon remaining before the commencement and completion of decommissioning, and the funding status of the trust. While maintaining an acceptable risk level consistent with the goal in subparagraph (A) of this paragraph, the investment emphasis when the remaining life of the liability, as defined in paragraph (2)(F)(iv) of this subsection, exceeds five years should be to maximize net long-term earnings. The investment emphasis in the remaining investment period of the trust should be on current income and the preservation of the fund's assets.

(D) In selecting investments, the impact of the investment on the portfolio's volatility and expected return net of fees, commissions, expenses and taxes should be considered.

(2) **General requirements.** The following requirements shall apply to all decommissioning trusts. Where a utility has multiple trusts for a single generating unit, the restrictions contained in this subsection apply to all trusts in the aggregate for that generating unit. For purposes of this section, a commingled fund is defined as a professionally managed investment fund of fixed-income or equity securities established by an investment company regulated by the Securities Exchange Commission or a bank regulated by the Office of the Comptroller of the Currency.

(A) Fees limitation. The total trustee and investment manager fees paid on an annual basis by the utility for the entire portfolio including commingled funds shall not exceed 0.7% of the entire portfolio's average annual balance.

(B) Diversification. For the purpose of this subparagraph, a commingled or mutual fund is not considered a security; rather, the diversification standard applies to all securities, including the individual securities held in commingled or mutual funds. Once the portfolio of securities (including commingled funds) held in the decommissioning trust(s) contains securities with an aggregate value in excess of $20 million, it shall be diversified such that:

(i) no more than 5.0 % of the securities held may be issued by one entity, with the exception of the federal government, its agencies and instrumentalities, and;

(ii) the portfolio shall contain at least 20 different issues of securities. Municipal securities and real estate investments shall be diversified as to geographic region.

(C) Qualified trusts. The utility may invest the decommissioning funds by means of qualified or unqualified nuclear decommissioning trusts; however, the utility shall, to the extent permitted by the Internal Revenue Service, invest its decommissioning funds in "qualified" nuclear decommissioning trusts, in accordance with the Internal Revenue Service Code §468A.

(D) Derivatives. The use of derivative securities in the trust is limited to those whose purpose is to enhance returns of the trust without a corresponding increase in risk or to reduce risk of the portfolio. Derivatives may not be used to increase the value of the portfolio by any amount greater than the value of the underlying securities. Prohibited derivative securities include, but are not limited to, mortgage strips; inverse floating rate securities; leveraged investments or internally leveraged securities; residual and support tranches of Collateralized Mortgage Obligations; tiered index bonds or other structured notes whose return characteristics are tied to non-market events; uncovered call/put options; large counter-party risk through over-the-counter options, forwards and swaps; and instruments with similar high-risk characteristics.

(E) The use of leverage (borrowing) to purchase securities or the purchase of securities on margin for the trust is prohibited.

(F) Investment limits in equity securities. The following investment limits shall apply to the percentage of the aggregate market value of all non-fixed income investments relative to the total portfolio market value.

(i) Except as noted in clause (ii), when the weighted average remaining life of the liability exceeds 5 years, the equity cap is 60%;

(ii) When the weighted average remaining life of the liability ranges between 5 years and 2.5 years, the equity cap shall be 30%. Additionally, during all years in which expenditures for decommissioning the nuclear units occur, the equity cap shall also be 30%;

(iii) When the weighted average remaining life of the liability is less than 2.5 years, the equity cap shall be 0%;

(iv) For purposes of this subparagraph, the weighted average remaining life in any given year is defined as the weighted average of years between the given year and the years of each decommissioning outlay, where the weights are based on each year's expected decommissioning expenditures divided by the amount of the remaining liability in that year; and

(v) Should the market value of non-fixed income investments, measured monthly, exceed the appropriate cap due to market fluctuations, the utility shall, as soon as practicable, reduce the market value of the non-fixed income investments below the cap. Such reductions may be accomplished by investing all future contributions to the fund in debt securities as is necessary to reduce the market value of the non-fixed income investments below the cap, or if prudent, by the sale of equity securities.

(G) A decommissioning trust shall not invest in securities issued by the electric utility collecting the funds or any of its affiliates; however, investments of a decommissioning trust may include commingled funds that contain securities issued by the electric utility if the securities of the utility constitute no more than 5.0% of the fair market value of the assets of such commingled funds at the time of the investment.

(3) **Specific investment restrictions.** The following restrictions shall apply to all decommissioning trusts. Where a utility has multiple trusts for a single generating unit, the restrictions contained in this subsection apply to all trusts in the aggregate for that generating unit.

(A) Fixed-income investments. A decommissioning trust shall not invest trust funds in corporate or municipal debt securities that have a bond rating below investment grade (below "BBB-" by Standard and Poor's Corporation or "Baa3" by Moody's Investor's Service) at the time that the securities are purchased and shall reexamine the appropriateness of continuing to hold a particular debt security if the debt rating of the company in question falls below investment grade at some time after the debt security has been purchased. Commingled funds may contain some below investment grade bonds; however, the overall portfolio of debt instruments shall have a quality level, measured quarterly, not below a "AA" grade by Standard and Poor's Corporation or "Aa2" by Moody's Investor's Service. In calculating the quality of the overall portfolio, debt securities issued by the federal government shall be considered as having a "AAA" rating.

(B) Equity investments.

(i) At least 70% of the aggregate market value of the equity portfolio, including the individual securities in commingled funds, shall have a quality ranking from a major rating service such as the earnings and dividend ranking for common stock by Standard and Poor's or the quality rating of Ford Investor Services. Further, the overall portfolio of ranked equities shall have a weighted average quality rating equivalent to the composite rating of the Standard and Poor's 500 index assuming equal weighting of each ranked security in the index. If the quality rating, measured quarterly, falls below the minimum quality standard, the utility shall as soon as practicable and prudent to do so, increase the quality level of the equity portfolio to the required level.

(ii) A decommissioning trust shall not invest in equity securities where the issuer has a capitalization of less than $100 million.

(C) Commingled funds. The following guidelines shall apply to the investments made through commingled funds. Examples of commingled funds appropriate for investment by nuclear decommissioning trust funds include United States equity-indexed funds, actively managed United States equity funds, balanced funds, bond funds, real estate investment trusts, and international funds.

(i) The commingled funds should be selected consistent with the goals specified in paragraph (1) and the requirements in paragraph (2) of this subsection.

(ii) In evaluating the appropriateness of a particular commingled fund, the utility has the following duties, which shall be of a continuing nature:

(I) A duty to determine whether the fund manager's fee schedule for managing the fund is reasonable, when compared to fee schedules of other such managers;

(II) A duty to investigate and determine whether the past performance of the investment manager in managing the commingled fund has been reasonable relative to prudent investment and utility decommissioning trust practices and standards; and

(III) A duty to investigate the reasonableness of the net after-tax return and risk of the fund relative to similar funds, and the appropriateness of the fund within the entire decommissioning trust investment portfolio.

(iii) The payment of load fees shall be avoided.

(iv) Commingled funds focused on specific market sectors or concentrated in a few holdings shall be used only as necessary to balance the trust's overall investment portfolio mix.

§25.303. Nuclear Decommissioning Following the Transfer of Texas Jurisdictional Nuclear Generating Plant Assets.

(a) **Purpose.** The purpose of this rule is to:

(1) delineate the rights and obligations of the transferor and the Transferee Companies involved in a transfer of Texas jurisdictional nuclear generating plant assets for which decommissioning funds will continue to be collected from retail customers pursuant to Public Utility Regulatory Act (PURA) §39.205, as well as the obligations of the utility responsible for collecting the decommissioning funds;

(2) prescribe a utility's continuing responsibility for collecting funds through its rates for nuclear decommissioning trust funds for the benefit of the Transferee Company;

(3) protect the nuclear decommissioning trust funds so that the funds collected from customers through the Collecting Utility's nonbypassable charge, plus the amounts earned from investment of the funds, will be available for decommissioning, in the event of a transfer of the nuclear decommissioning trust funds;

(4) minimize the amounts collected from customers for nuclear decommissioning by maximizing net earnings on the nuclear decommissioning trust funds through prudent investment of such funds, in accordance with the guidelines set out in subsection (e)(3)(A)(iii) of this section, and achieving optimum tax efficiency, in accordance with subsection (e)(3)(B)(iii) of this section.

(b) **Application.** This rule supersedes §25.231(b)(1)(F) of this title (relating to Cost of Service) and §25.301 of this title (relating to Nuclear Decommissioning Trusts) for electric utilities that have completed their business separation pursuant to PURA §39.051 or that otherwise transfer Texas jurisdictional nuclear generating plant assets, including the associated nuclear decommissioning trust funds, to another entity. This rule applies to:

(1) an electric utility or a power generation company that transfers its Texas jurisdictional nuclear generating plant assets, including any associated nuclear decommissioning trust funds, to another entity;

(2) a utility that is responsible for collecting revenue for the decommissioning of Texas jurisdictional nuclear generating plant assets that have been transferred to another entity; and

(3) a Transferee Company.

(c) **Definitions.**

(1) Transferor Company—An electric utility, its successor in interest, or any power generation company that transfers Texas jurisdictional nuclear generating plant assets, including any associated nuclear decommissioning trust funds collected from customers.

(2) Transferee Company—An entity or its successor in interest to which Texas jurisdictional nuclear decommissioning generating plant assets, including the associated nuclear decommissioning trust funds, are transferred from a Transferor Company. For purposes of this section, a municipality or an electric cooperative may be a Transferee Company.

(3) Collecting Utility—The electric utility or transmission and distribution utility responsible for collecting the decommissioning funds from customers and depositing them into the nuclear decommissioning trust funds. The Collecting Utility may or may not be the Transferor Company.

(4) Nuclear Decommissioning Trust Funds—Funds that are contained in one or more external and irrevocable trusts created for the purpose of protecting and holding revenue collected under cost-of-service rate regulation to cover the costs of decommissioning a Texas jurisdictional nuclear generating plant at the end of its useful life.

(5) Decommissioning Funds Collection Agreement—An agreement between or agreements among the Collecting Utility, the Transferor Company (if different from the Collecting Utility), and the

Transferee Company that govern the transfer of responsibility for administration of the nuclear decommissioning trust funds, the collection of decommissioning revenues from utility customers, and the remittance of the funds to the nuclear decommissioning trust.

(d) **Transfer of Nuclear Decommissioning Trust Funds.**

(1) Prior to the closing of any transaction involving the transfer of nuclear decommissioning trust funds:

(A) The Collecting Utility, the Transferor Company (if different from the Collecting Utility), and the Transferee Company shall jointly submit for the commission's review the proposed decommissioning funds collection agreement(s) and the proposed agreements with the institutional trustee and investment manager(s) of the decommissioning trust, and copies shall be provided to the commission's Legal and Enforcement Division and Financial Review Division. The Collecting Utility or Transferee Company may request the transfer of responsibility for administration of the nuclear decommissioning trust funds to the Transferee Company in a contested case proceeding pursuant to subsection (d)(6)(E) of this section at the time of submission of such agreements or anytime thereafter.

(B) In connection with the submission required in subparagraph (A) of this paragraph, the Transferee Company shall submit an affidavit, signed under oath by an authorized officer of the Transferee Company, certifying that once the transfer of administration of the Nuclear Decommissioning Trust Funds is ordered by the commission, the transferred funds and the future contributions to the funds will be administered in accordance with subsection (e) of this section and that the company will not challenge the authority of the commission to enforce its rules that shall be adopted from time to time relating to the collection, investment and use of the funds provided by Collecting Utility customers for nuclear decommissioning.

(2) For transfers of Nuclear Decommissioning Trust Funds that occurred before this rule took effect, the executed decommissioning funds collection agreement(s) and agreements with the institutional trustee and investment manager(s) shall be filed at the commission within 15 days of the effective date of this rule, unless such agreements have previously been filed with the commission. If such agreements must be amended to comply with this section, the amended agreements must take effect on or before the Collecting Utility's next general rate proceeding or a rate proceeding under subsection (g) of this section, whichever occurs first.

(3) Prior to executing an amended decommissioning funds collection agreement or amended agreement with the institutional trustee or investment managers, the proposed amended agreement shall be filed at the commission for review along with a redlined version showing all changes made since the document was reviewed by the commission, and copies shall be provided to the commission's Legal and Enforcement Division and Financial Review Division.

(4) A Transferee Company shall maintain one or more irrevocable trusts external to the Transferee Company for the purpose of receiving the nuclear decommissioning revenues collected under cost-of-service rate regulation. The Transferee Company shall be named as beneficiary of each such trust. If the Transferee Company has an existing trust for the same generating unit in which an interest is being transferred that is funded by a set of ratepayers entirely distinct from that of the Collecting Utility's ratepayers, or funded by other sources, a separate trust or separate subaccount shall be maintained that will segregate the decommissioning funds received from the Collecting Utility, and any earnings thereon, from the nuclear decommissioning trust funds received from other sources. There shall be no commingling of any decommissioning funds received from the Collecting Utility with any other trust or subaccount containing nuclear decommissioning trust funds received from any other set of ratepayers or other sources. If a single trust with subaccounts is utilized to hold the decommissioning funds, the Transferee Company shall cause to be

performed an independent audit of all said subaccounts and shall otherwise act to recognize the interests of different sets of ratepayers as may reasonably be requested by the commission.

(5) The Collecting Utility, the Transferor Company (if different from the Collecting Utility), and the Transferee Company shall execute a decommissioning funds collection agreement. The agreement shall provide that the Transferor Company's rights to accumulated and future decommissioning funds and the responsibilities for decommissioning of the nuclear plant shall be transferred to the Transferee Company upon closing of the transaction. The decommissioning funds collection agreement may provide for the remittance by the Collecting Utility of levelized periodic payments based on the most recent annual decommissioning funding amount approved by the commission or the actual amounts of nonbypassable decommissioning charges collected by the Collecting Utility during each applicable remittance period, or for such other remittance arrangement as the commission concludes is reasonable and consistent with the purposes of this section. In the selection of a remittance arrangement, the parties to the decommissioning funds collection agreement shall consider the impact on optimum tax efficiency pursuant to subsection (e)(3)(B)(iii).

(6) After the Collecting Utility, the Transferor Company (if different from the Collecting Utility), and Transferee Company have filed a request for a commission review of the agreements filed pursuant to subsection (d)(1)(A) or (d)(3) of this section:

(A) The commission staff will recommend approval, amendment, or disapproval of the agreements within 60 days of receipt of the request.

(B) If the commission staff recommends approval, and no motions for intervention have been filed, the commission shall promptly approve the request;

(C) If the commission staff recommends amendment, within 14 days after staff's recommendation the filing parties shall either file amended agreements incorporating the amendments, request review of alternative language, or request a hearing.

(D) If the applicants file amended agreements incorporating the staff recommendations, and there is no motion to intervene filed, the commission shall promptly approve the amended request.

(E) If the commission staff recommends denial, if the applicants request a hearing, or if the applicants do not file amended agreements incorporating staff's recommendations within 14 days pursuant to subsection (d)(6)(C), the request shall be docketed as a contested case proceeding to approve, modify, or reject the agreements. The commission will issue an order within 120 days of the initiation of a contested case proceeding. In considering whether or not to approve the decommissioning funds collection agreement, the commission may consider the impact on customers including any impact on federal income taxes related to the nuclear decommissioning trust funds, the ability of the Transferee Company to administer the trust, any investment restrictions on the Transferee Company, the ability of the commission to enforce its rules over the administrator of the funds, and any other relevant factors.

(F) An agreement filed pursuant to subsection (d)(1)(A) and (d)(3) of this section shall be filed at the commission within 15 days of the execution of the agreement.

(7) Absent a commission order to the contrary, the Collecting Utility shall be the administrator of the nuclear decommissioning trust funds established or maintained by the Transferee Company and shall be responsible for administering the funds in accordance with subsection (e) of this section.

(8) Upon the issuance of an order from the commission releasing the Collecting Utility from the obligation to administer the nuclear decommissioning trust funds, the Transferee Company that owns the nuclear decommissioning trust funds shall become the administrator of such funds in accordance with subsection (e) of this section.

(e) **Administration of the Nuclear Decommissioning Trust Funds.**

(1) **Duties of funds administrator.**

(A) Each funds administrator of Nuclear Decommissioning Trust Funds shall assure that the Nuclear Decommissioning Trust Funds are managed so that the funds are secure and are invested consistent with the goals in this subsection; and so that the funds provided from the Collecting Utility's nonbypassable charge, plus the amounts earned from investment of the funds, will be available at the time of decommissioning.

(B) The funds administrator shall appoint one or more institutional trustees and may appoint one or more investment managers. Unless otherwise specified in paragraph (2) of this subsection, the Texas Trust Code controls the administration and management of the Nuclear Decommissioning Trust Funds, except that the appointed trustees need not be qualified to exercise trust powers in Texas. If the Collecting Utility is the acting funds administrator, the selection or replacement of such trustees and investment managers shall be made in consultation with the Transferee Company. The agreements with such trustees and investment managers shall require that any reports regarding the trust funds given to the fund administrator shall also be given to the Transferee Company, if different from the fund administrator.

(C) The funds administrator shall retain the right to replace the trustees with or without cause. In appointing a trustee, the funds administrator shall have the following duties, which will be of a continuing nature:

(i) A duty to determine whether the trustee's fee schedule for administering the trust is reasonable, when compared to other institutional trustees rendering similar services, and meets the requirement of paragraph (3)(B)(i) of this subsection;

(ii) A duty to investigate and determine whether the past administration of trusts by the trustee has been reasonable;

(iii) A duty to investigate and determine whether the financial stability and strength of the trustee is adequate;

(iv) A duty to investigate and determine whether the trustee has complied with the trust agreement and this section as it relates to trustees; and,

(v) A duty to investigate any other factors which may bear on whether the trustee is suitable.

(D) The funds administrator shall retain the right to replace the investment managers with or without cause. In appointing an investment manager, the funds administrator shall have the following duties, which will be of a continuing nature:

(i) A duty to determine whether the investment manager's fee schedule for investment management services is reasonable, when compared to other such managers, and meets the requirement of paragraph (3)(B)(i) of this subsection;

(ii) A duty to investigate and determine whether the past performance of the investment manager in managing investments has been reasonable;

(iii) A duty to investigate and determine whether the financial stability and strength of the investment manager is adequate for purposes of liability;

(iv) A duty to investigate and determine whether the investment manager has complied with the investment management agreement and this section as it relates to investments; and,

(v) A duty to investigate any other factors which may bear on whether the investment manager is suitable.

(2) **Agreements between the fund administrator and the institutional trustee or investment manager.**

(A) The fund administrator shall execute an agreement with each institutional trustee. The agreement shall include the restrictions in subparagraphs (A)(i)-(v) of this paragraph and may include additional restrictions on the trustee. A fund administrator shall not grant such trustee powers that are greater than those provided to trustees under the Texas Trust Code or that are inconsistent with the limitations of this section.

(i) The interest earned on the corpus of the trust becomes part of the trust corpus. A trustee owes the same duties with regard to the interest earned on the corpus as are owed with regard to the corpus of the trust.

(ii) A trustee shall have a continuing duty to review the trust portfolio for compliance with investment guidelines and governing regulations.

(iii) A trustee shall not lend funds from the decommissioning trust to itself, its officers, or its directors.

(iv) A trustee shall not invest or reinvest decommissioning trust funds in instruments issued by the trustee, except for time deposits, demand deposits, or money market accounts of the trustee. However, investments of a decommissioning trust may include mutual funds that contain securities issued by the trustee if the securities of the trustee constitute no more than five percent of the fair market value of the assets of such mutual funds at the time of the investment.

(v) The agreement shall comply with all applicable requirements of the Nuclear Regulatory Commission.

(B) The fund administrator shall execute an agreement with each investment manager. (If the trustee performs investment management functions, the contractual provisions governing those functions must be included in either the trust agreement or a separate investment management agreement.) The agreement shall include the restrictions set forth in subparagraphs (B)(i)-(v) of this paragraph and may include additional restrictions on the manager. A funds administrator shall not grant the manager powers that are greater than those provided to trustees under the Texas Trust Code or that are inconsistent with the limitations of this section.

(i) An investment manager shall, in investing and reinvesting the funds in the trust, comply with paragraph (3) of this subsection.

(ii) The interest earned on the corpus of the trust becomes part of the trust corpus. An investment manager owes the same duties with regard to the interest earned on the corpus as are owed with regard to the corpus of the trust.

(iii) An investment manager shall have a continuing duty to review the trust portfolio to determine the appropriateness of the investments.

(iv) An investment manager shall not invest funds from the decommissioning trust with itself, its officers, or its directors.

(v) The agreement shall comply with all applicable requirements of the Nuclear Regulatory Commission.

(3) **Trust investments.**

(A) **Investment portfolio goals.** The Nuclear Decommissioning Trust Funds should be invested consistent with the following goals. The funds administrator may apply additional prudent investment goals to the funds so long as they are not inconsistent with the stated goals of this subsection.

(i) The funds should be invested with a goal of earning a reasonable return commensurate with the need to preserve the value of the assets of the trusts.

(ii) In keeping with prudent investment practices, the portfolio of securities held in the decommissioning trust shall be diversified to the extent reasonably feasible given the size of the trust.

(iii) Asset allocation and the acceptable risk level of the portfolio should take into account market conditions, the time horizon remaining before the commencement and completion of decommissioning, and the funding status of the trust. While maintaining an acceptable risk level consistent with the goal in subparagraph (A)(i) of this paragraph, the investment emphasis when the remaining life of the liability, as defined in subparagraph (B)(vi)(IV) of this paragraph, exceeds five years should be to maximize net long-term earnings. The investment emphasis in the remaining investment period of the trust should be on current income and the preservation of the fund's assets.

(iv) In selecting investments, the impact of the investment on the portfolio's volatility and expected return net of fees, commissions, expenses, and taxes should be considered.

(B) **General requirements.** The following requirements shall apply to all Nuclear Decommissioning Trust Funds. Where a Transferee Company has multiple Nuclear Decommissioning Trust Funds for a single generating unit, the restrictions contained in this subsection apply to all such trusts in the aggregate for that generating unit. For purposes of this section, a commingled fund is defined as a professionally managed investment fund of fixed-income or equity securities established by an investment company regulated by the Securities Exchange Commission or a bank regulated by the Office of the Comptroller of the Currency.

(i) **Fees limitation.** The total trustee and investment manager fees paid on an annual basis by the fund administrator from the trust for the entire portfolio including commingled funds shall not exceed 0.7% of the entire portfolio's average annual balance.

(ii) **Diversification.** For the purpose of this subparagraph, a commingled or mutual fund is not considered a security; rather, the diversification standard applies to all securities, including the individual securities held in commingled or mutual funds. Once the portfolio of securities (including commingled funds) held in the decommissioning trust(s) contains securities with an aggregate value in excess of $20 million, it shall be diversified such that:

(I) no more than 5.0% of the securities held may be issued by one entity, with the exception of the federal government, its agencies and instrumentalities, and;

(II) the portfolio shall contain at least 20 different issues of securities. Municipal securities and real estate investments shall be diversified as to geographic region.

(iii) **Optimum tax efficiency.** The fund administrator may invest the decommissioning funds by means of tax exempt, "qualified" or "unqualified" nuclear decommissioning trusts; however, the fund administrator shall, to the extent permitted by the Internal Revenue Service, invest any taxable decommissioning funds in "qualified" nuclear decommissioning trusts, in accordance with the Internal Revenue Code §468A (or any successor thereto). The fund administrator shall avoid, whenever possible, the investment of taxable decommissioning funds in "unqualified" nuclear decommissioning trusts.

(iv) **Derivatives.** The use of derivative securities in the trust is limited to those whose purpose is to enhance returns of the trust without a corresponding increase in risk or to reduce risk of the portfolio. Derivatives may not be used to increase the value of the portfolio by any amount greater than the value of the underlying securities. Prohibited derivative securities include, but are not limited to, mortgage strips; inverse floating rate securities; leveraged investments or internally leveraged securities; residual and support tranches of Collateralized Mortgage Obligations; tiered index bonds or other structured notes whose return characteristics are tied to non-market events; uncovered call/put options; large counter-party risk through over-the-counter options, forwards and swaps; and instruments with similar high-risk characteristics.

(v) The use of leverage (borrowing) to purchase securities or the purchase of securities on margin for the trust is prohibited.

(vi) **Investment limits in equity securities.** The following investment limits shall apply to the percentage of the aggregate market value of all non-fixed income investments relative to the total portfolio market value.

(I) Except as noted in subclause (II) of this clause, when the weighted average remaining life of the liability exceeds five years, the equity cap is 60%.

(II) When the weighted average remaining life of the liability ranges between five years and two and a half years, the equity cap shall be 30%. Additionally, during all years in which expenditures for decommissioning the nuclear units occur, the equity cap shall also be 30%.

(III) When the weighted average remaining life of the liability is less than two and a half years, the equity cap shall be 0%.

(IV) For purposes of this subparagraph, the weighted average remaining life in any given year is defined as the weighted average of years between the given year and the years of each decommissioning outlay, where the weights are based on each year's expected decommissioning expenditures divided by the amount of the remaining liability in that year.

(V) Should the market value of non-fixed income investments, measured monthly, exceed the appropriate cap due to market fluctuations, the fund administrator shall, as soon as practicable, reduce the market value of the non-fixed income investments below the cap. Such reductions may be accomplished by investing all future contributions to the fund in debt securities as is necessary to reduce the market value of the non-fixed income investments below the cap, or if prudent, by the sale of equity securities.

(vii) A decommissioning trust shall not invest in securities issued by the Transferee Company or the Collecting Utility collecting the funds or any of their respective affiliates; however, investments of a decommissioning trust may include commingled funds that contain securities issued by the Transferee Company or Collecting Utility if the securities of such company or utility constitute no more than 5.0% of the fair market value of the assets of such commingled funds at the time of the investment.

(C) **Specific investment restrictions.** The following restrictions shall apply to all decommissioning trusts. Where a Transferee Company has multiple Nuclear Decommissioning Trust Funds for a single generating unit, the restrictions contained in this subsection apply to all such trusts in the aggregate for that generating unit.

(i) **Fixed-income investments.** A decommissioning trust shall not invest trust funds in corporate or municipal debt securities that have a bond rating below investment grade (below "BBB-" by Standard and Poor's Corporation or "Baa3" by Moody's Investor's Service) at the time that the securities are purchased and shall reexamine the appropriateness of continuing to hold a particular debt security if the debt rating of the company in question falls below investment grade at some time after the debt security has been purchased. Commingled funds may contain some below-investment-grade bonds; however, the overall portfolio of debt instruments shall have a quality level, measured quarterly, not below an "AA" grade by Standard and Poor's Corporation or "Aa2" by Moody's Investor's Service. In calculating the quality of the overall portfolio, debt securities issued by the federal government shall be considered as having an "AAA" rating.

(ii) **Equity investments.**

(I) At least 70% of the aggregate market value of the equity portfolio, including the individual securities in commingled funds, shall have a quality ranking from a major rating service, such as the earnings and dividend ranking for common stock by Standard and Poor's or the quality rating of Ford Investor Services. Further, the overall portfolio of ranked equities shall have a weighted average quality rating equivalent to the composite rating of the Standard and Poor's 500 index assuming equal weighting of each ranked security in the index. If the quality rating, measured quarterly, falls below the minimum quality standard, the fund administrator shall as soon as practicable and prudent to do so, increase the quality level of the equity portfolio to the required level.

(II) A decommissioning trust shall not invest in equity securities where the issuer has a capitalization of less than $100 million.

(iii) **Commingled funds.** The following guidelines shall apply to the investments made through commingled funds. Examples of commingled funds appropriate for investment by nuclear decommissioning trust funds include United States equity-indexed funds, actively managed United States equity funds, balanced funds, bond funds, real estate investment trusts, and international funds.

(I) The commingled funds should be selected consistent with the goals specified in paragraph (1) and the requirements in paragraph (2) of this subsection.

(II) In evaluating the appropriateness of a particular commingled fund, the fund administrator has the following duties, which shall be of a continuing nature:

(-a-) A duty to determine whether the fund manager's fee schedule for managing the fund is reasonable, when compared to fee schedules of other such managers;

(-b-) A duty to investigate and determine whether the past performance of the investment manager in managing the commingled fund has been reasonable relative to prudent investment and utility decommissioning trust practices and standards; and

(-c-) A duty to investigate the reasonableness of the net after-tax return and risk of the fund relative to similar funds, and the appropriateness of the fund within the entire decommissioning trust investment portfolio.

(III) The payment of load fees shall be avoided.

(IV) Commingled funds focused on specific market sectors or concentrated in a few holdings shall be used only as necessary to balance the trust's overall investment portfolio mix.

(f) **Periodic reviews of decommissioning costs and Nuclear Decommissioning Trust Funds.**

(1) Following a transfer of Texas jurisdictional nuclear generating plant assets, including the associated Nuclear Decommissioning Trust Funds, any remaining costs associated with nuclear decommissioning obligations shall remain subject to cost-of-service regulation based on a periodic review of such costs pursuant to subsections (f)(3) or (g)(4) of this section. The reasonable and necessary nuclear decommissioning costs as periodically approved by the commission shall continue to be included as a nonbypassable charge of the Collecting Utility associated with the Texas jurisdictional nuclear plant asset. Subsection (g) of this section shall apply to such charges by a Collecting Utility.

(2) The Transferee Company shall periodically perform, or cause to be performed, a study of the decommissioning costs of each Texas jurisdictional nuclear generating unit it owns or in which it leases an interest. A study or re-determination of the previous study shall be performed at least every five years, starting from the date of the most recent decommissioning cost study for the plant on file with the commission. The study or re-determination shall consider the most current and reasonably available information on the cost of decommissioning. A copy of the study or re-determination along with an updated funding analysis shall be filed with the commission and copies provided to the commission's Financial Review Division and the Office of Public Utility Counsel. The funding analysis shall be based on the most current information reasonably available for the cost of decommissioning, an allowance for contingencies of 10% of the cost of decommissioning, the balance of funds in the decommissioning trusts, anticipated escalation rates, the anticipated after-tax return on the funds in the trust, and other relevant factors. The funding analysis shall be accompanied by a description of the assumptions used in the analysis and shall calculate the required annual funding amount necessary to ensure sufficient funds to decommission the nuclear generating plant at the end of its useful life.

(3) The commission, on its own motion or on the motion of the Legal and Enforcement Division, the Office of Public Utility Counsel, or any affected person, may initiate a proceeding to review the Transferee Company's trust balances, compliance with this section, or the annual funding amount. The Transferee Company shall provide any information required to conduct the review upon request in accordance with the commission's procedural rules.

(4) During each periodic review of decommissioning costs, the following evidence shall be provided:

   (A) The Transferee Company shall file the periodic cost study described in paragraph (2) of this subsection, along with an updated decommissioning funding analysis described in paragraph (2) of this subsection, within 90 days of completion of the periodic cost study. The cost study and funding analysis shall be accompanied by a report or testimony supporting the analyses and the requested annual funding amount.

   (B) The Nuclear Decommissioning Trust Funds administrator shall demonstrate that the decommissioning funds are being invested prudently and in compliance with the investment guidelines in subsection (e) of this section.

   (C) To the extent the Transferee Company is subject to investment restrictions that are more restrictive than the decommissioning investment guidelines in subsection (e) of this section, the Transferee Company (or the funds administrator and the Transferee Company, if different) shall demonstrate their efforts to obtain relief from such investment restrictions in order to permit investments in accordance with the guidelines in subsection (e) of this section.

   (D) The Transferee Company (or the funds administrator and the Transferee Company, if different) shall demonstrate efforts to achieve optimum tax efficiency as defined in subsection (e)(3)(B)(iii) of this section, including, as applicable, maintenance of tax-exempt status or efforts to achieve "qualified" status in accordance with Internal Revenue Code §468A (or any successor thereto) with respect to its taxable nuclear decommissioning trust funds.

(5) Within 90 days after completion of decommissioning the nuclear generating plant, the Transferee Company shall file a request for a final reconciliation proceeding at the commission. Any funds remaining in the trust after the completion of decommissioning shall be refunded to customers in a manner determined by the commission. If the reasonable and necessary costs of decommissioning exceed the amount available in the trust, the excess costs will be recovered through a nonbypassable charge approved by the commission if the Transferee Company has substantially complied with this section and prudently managed the decommissioning process.

(6) The Transferee Company shall file an annual report on May 15 of each year to report the status of the decommissioning trust fund using a form approved by the commission.

(7) The Collecting Utility, as part of its annual earnings report, shall report the amounts and dates of the deposits into the Nuclear Decommissioning Trust Funds and, if different, the revenues received from customers for the time intervals corresponding to each deposit.

(g) **Collecting utility rate proceedings for decommissioning charges.**

(1) A Collecting Utility that has decommissioning expenses embedded as part of a bundled rate shall apply to have its current level of decommissioning funding removed from its general rates and stated as a separate nonbypassable charge.

(A) In the case of a transfer of Texas jurisdictional nuclear generating plant assets to a non-affiliated entity, the request shall be made no later than 30 days following the closing of the transaction. The nonbypassable charge shall be based on the funding level and the rate class allocation methodology as approved in the Collecting Utility's last general rate proceeding. Such proceeding to remove the decommissioning charge from the Collecting Utility's general rates and state it as a separate nonbypassable charge will not constitute a general rate case.

(B) In the case of a transfer of Texas jurisdictional nuclear generating plant assets to an affiliated power-generating company, the request for a separate nonbypassable charge shall be made during the first general rate case following the transfer.

(2) The Collecting Utility shall deposit the decommissioning revenues into the Nuclear Decommissioning Trust Funds consistent with the terms of the decommissioning funds collection agreement on file with the commission and the most recent commission order authorizing decommissioning collections from customers.

(A) The commission may on its own motion or on the motion of the Legal and Enforcement Division, the Office of Public Utility Counsel or any other affected person, initiate a proceeding to discontinue the deposit of decommissioning revenues to the Nuclear Decommissioning Trust Funds if the Transferee Company substantially or repeatedly fails to comply with any provision of this section.

(B) If levelized deposits are made into the fund, the following provisions apply.

(i) The Collecting Utility shall keep records of its daily receipts from customers once a separate nonbypassable charge is set by the commission.

(ii) Once the Collecting Utility has implemented a separate nonbypassable charge, it shall request an adjustment in the nonbypassable charge if there is, and is projected to continue to be, a material cumulative over- or under-collection of revenues, including interest, greater than or equal to 15% of the most recent annual nuclear decommissioning funding amount approved by the commission. The request shall be based on the difference between the actual cumulative decommissioning charge revenues collected from customers and the cumulative amount authorized to be collected since the last rate adjustment, including interest calculated in accordance with §25.236(e)(1) of this title (relating to Recovery of Fuel Costs). The calculated over- or under-recovery amount will be applied to the commission-authorized annual amount to determine the required nonbypassable charge.

(C) If deposits to the nuclear decommissioning trust funds are less frequent than weekly, an implied interest calculation shall be used in setting the decommissioning charge to account for the Collecting Utility's short term use of the funds.

(3) Upon the issuance of a commission order under subsection (f)(3) or (g)(4) of this section in which the commission determines that the annual funding amount required for nuclear decommissioning for a particular plant has increased or decreased and should be adjusted, the Collecting Utility shall file a rate application within 45 days solely to adjust the nonbypassable charge. The filing shall provide sales data, a proposed allocation methodology, a proposed tariff, and any other information necessary to implement the commission's order. The commission will issue a final order within 120 days of receipt of the filing. Such rate proceeding will be conducted separately from the Collecting Utility's general rate proceedings.

(4) The Transferee Company may elect to request a change in the decommissioning funding level during a general rate case of the Collecting Utility. The Collecting Utility shall give the Transferee Company at least 90 days' notice of an anticipated rate application for its general rates to allow the Transferee Company to prepare a funding analysis to be filed jointly with the Collecting Utility's application.

(h) **Good cause exception.** Upon a showing of good cause, an applicant under this section may request that the commission waive or grant an exception to any requirement of this section.

§25.304. Nuclear Decommissioning Funding and Requirements for Power Generation Companies.

(a) **Purpose.** The purpose of this section is to establish the terms for power generation companies (PGCs) that are licensed by the Nuclear Regulatory Commission for using a PGC decommissioning trust to satisfy the financial assurance requirements for decommissioning a nuclear generating unit and to delineate the rights and obligations of PGCs electing to use a commission-approved method for providing funds from Texas customers for decommissioning a nuclear generating unit, as a means of complying with nuclear decommissioning financial assurance requirements.

(1) A PGC is not required to use the methods set out in this section and may discontinue the use of the methods set out in this section, if it chooses to satisfy the financial assurance requirements of the federal Nuclear Regulatory Commission by using other methods acceptable to the Nuclear Regulatory Commission.

(2) A PGC decommissioning trust established in accordance with this section is separate from a Nuclear Decommissioning Trust created under §25.303 of this title (relating to Nuclear Decommissioning Following the Transfer of Texas Jurisdictional Nuclear Generating Plant Assets).

(b) **Applicability.** A PGC owning all or a portion of a qualifying nuclear generating unit may use a PGC decommissioning trust as an external sinking fund in compliance with this section, provided that the use of the methods of financial assurance set out in this section shall be available only to the first six nuclear generating units the construction of which begins on or after January 1, 2013, and before January 1, 2033, that elect to use a PGC decommissioning trust.

(c) **Definitions.**

(1) Decommissioning--includes the safe decommissioning and decontamination of a nuclear generating unit, equipment, and materials consistent with federal Nuclear Regulatory Commission requirements.

(2) PGC decommissioning trust--Funds that are contained in one or more external and irrevocable trusts created for the purpose of protecting and holding revenue collected from a PGC to cover the costs of decommissioning a Texas jurisdictional nuclear generating plant at the end of its useful life. A PGC decommissioning trust is a type of external sinking fund that is established and maintained by setting aside funds periodically in an account segregated from the PGC's assets and outside the PGC's administrative control in which the total amount of funds would be sufficient to pay decommissioning costs at the time termination of operations is expected.

(3) Retail electric customer--A retail electric customer in a geographic area of Texas in which retail customer choice has been implemented, or a retail electric customer of a municipally-owned utility or electric cooperative that has an agreement to purchase power from a nuclear generating unit.

(4) Under construction--A nuclear generating unit for which the PGC has initiated the pouring of safety-related concrete for the reactor building.

(d) **Application.** If a PGC elects to use a PGC decommissioning trust, the PGC shall submit an application to the commission for an order establishing the amount of annual decommissioning funding and approving trust agreements. A PGC may combine applications for more than one qualifying nuclear generating unit. An application must contain the following information:

(1) Identification of each nuclear generating unit included in the application;

(2) Quantification of the PGC's percentage of ownership of each unit;

(3) Decommissioning cost study using the most currently available information on the cost of decommissioning each unit as set out in subsection (h)(2) of this section;

(4) Funding analysis identifying the expected amount of annual decommissioning funding determined as set out in subsection (i) of this section;

(5) Description of the method to be used to satisfy the state assurance obligation set forth in subsection (k) of this section, including any guarantee agreements, support agreements, credit agreements, or letters of credit or surety bonds;

(6) Agreements with an institutional trustee and investment manager to manage the PGC decommissioning trust that are consistent with this section and the terms and conditions required by the federal Nuclear Regulatory Commission; and

(7) Projected date for beginning funding of the PGC decommissioning trust, which must be prior to the commencement of initial fuel load and commercial operation of the nuclear generating unit.

(e) **Commission Review.**

(1) The commission staff will endeavor to recommend approval, amendment, or disapproval of an application setting annual decommissioning funding and financial agreements to implement the trust requirements within 120 days of receipt of a sufficient application, unless a hearing on the application is required.

(2) A request for hearing shall be filed by the date specified by the presiding officer which shall be no more than 60 days after the filing of the application. If a hearing is scheduled, the commission will endeavor to issue a final order within 180 days after the filing of a request for hearing.

(3) If no hearing is requested, the commission staff concludes that the application setting annual decommissioning funding and the trust agreements meet all requirements of this section, and the commission staff recommends approval, the application may be approved administratively or informally pursuant to §22.35 of this title (relating to Informal Disposition).

(4) If the commission staff recommends an amendment to the funding or trust agreements, within 14 days after filing of staff's recommendation, the PGC shall either file an amended application incorporating the staff's proposed amendments or request a hearing.

(5) If no hearing is requested and the PGC files an amended application that meets all requirements of this section and incorporates the staff recommendations, the application may be approved administratively or informally pursuant to §22.35 of this title.

(6) If the commission staff recommends denial and the PGC requests a hearing, or if the PGC does not file an amended application incorporating staff's recommendations within 14 days, the request shall be docketed as a contested case proceeding to approve, modify, or reject the application.

(f) **Order.** An order approving the application shall establish the amount of annual funding necessary to meet the decommissioning obligations for the nuclear generating unit over the unit's operating license period as established by the federal Nuclear Regulatory Commission or over a shorter period of time at the election of the PGC.

(g) **Annual Reports.** On or before May 1 of each year, each PGC for which the commission has approved a funding amount and trust agreements under this section shall file an annual report for the prior year using a form approved by the commission. The report shall provide the status of the PGC's decommissioning trusts and any changes in the administration of the trusts, an update of its ability to fund the PGC decommissioning trust; and other information specified by the commission in the form.

(h) **Periodic Commission Review.** At least once every three years the PGC shall file a decommissioning cost study and funding analysis or updates of previous studies using the most current information reasonably available to the PGC.

(1) The commission shall review the studies submitted by a PGC and other currently available information using the procedure provided in subsection (e) of this section.

(2) During the initial and each periodic review of decommissioning costs, the following information shall be provided:

(A) The decommissioning cost study and funding analysis accompanied by a report and testimony supporting the analysis and the requested annual funding amount. The funding analysis shall be based on the most current information reasonably available concerning the cost of decommissioning, an allowance for contingencies of not more than 10% of the cost of decommissioning, the balance of funds in the decommissioning trusts, anticipated escalation rates, the anticipated after-tax return on the funds in the trust, and other relevant factors. In no event will the cost estimate for basic radiological decommissioning be less than the minimum amount required by the federal Nuclear Regulatory Commission. The funding analysis shall be accompanied by a description of the assumptions used in the analysis and shall calculate the required annual funding amount necessary to ensure sufficient funds to decommission the nuclear generating plant at the end of its useful life.

(B) A demonstration that the decommissioning funds are being or will be invested prudently and in compliance with the investment guidelines in subsection (o) of this section.

(C) A demonstration of efforts to achieve optimum tax efficiency as defined in subsection (o)(2)(C) of this section, including, as applicable, maintenance of tax-exempt status or efforts to achieve "qualified" status in accordance with Internal Revenue Code §468A (or any successor thereto) with respect to the PGC's taxable PGC decommissioning trusts.

(D) Confirmation that the federal Nuclear Regulatory Commission either has made, or will make, a finding that there is reasonable assurance of the financial qualifications of the PGC, as required by federal regulations.

(E) Compliance with the state funding assurance obligation set forth in subsection (k) of this section.

(3) The commission shall ensure that the amount of annual decommissioning funding is consistent with the most recent decommissioning cost study and funding analysis, and that the PGC decommissioning trust is adequately funded. The PGC shall update its state assurance obligation to reflect changes in the annual decommissioning funding amount.

(i) **Annual Decommissioning Funding Amount.** The amount of annual decommissioning funding for a PGC decommissioning trust shall be an amount that, based on such factors as the balance of funds in the decommissioning trust, anticipated escalation rates, and anticipated after-tax return on funds in the decommissioning trust, will cover the cost of decommissioning a nuclear generating unit at the end of its operating license period. The amount shall be calculated based on the most current reasonably available information, consistent with the most recent decommissioning cost study, and divided by the remaining years of the license or a shorter period of time at the election of the PGC. The decommissioning cost study and funding analysis shall include the information required by subsection (h)(2)(A) of this section. The commission, on its own motion or on the motion of the commission staff, may initiate a proceeding to review the PGC's trust balances or the annual funding amount. The PGC shall provide any information required to conduct the review in accordance with the commission's procedural rules.

(j) **Creditworthiness of PGC.** For the purposes of the initial application under this section, creditworthiness of the PGC will be established primarily through satisfying the State Assurance Obligation as provided for in subsection (k) of this section.

(k) **State Assurance Obligation.** A PGC using a commission approved PGC decommissioning trust shall provide additional financial assurances that funds will be available to satisfy 16 years of annual decommissioning funding, based on the most recent annual decommissioning funding amount approved by the commission (the state assurance obligation amount). If the remaining funding contribution period is less than 16 years, the state assurance obligation will be based on the remaining number of years of annual decommissioning funding. The state assurance obligation amount will be the discounted value of annual decommissioning funding for the relevant period up to 16 years. Any arrangement for satisfying the state assurance obligation shall permit the trustee of a decommissioning trust to demand payment by any company holding funds or providing an assurance and require the company holding funds or providing an assurance to remit funds to the trust, in accordance with this section. The PGC shall include in its annual report a demonstration of compliance with the requirements of this subsection. The state assurance may be used to provide assurance required by state or federal law for other similar purposes relating to the operation of the facility, such as assurance for the funding to cover estimated operation costs, provided that adequate terms are included to replenish the amounts available under the assurance mechanism if funds are withdrawn for any such other purpose. The state assurance obligation may be accomplished by using one or more of the following methods at the election of the PGC, in the form approved by the commission:

(1) A PGC may satisfy the state assurance obligation by depositing the required amount of funds into an escrow account, a government fund, a nuclear decommissioning trust subject to the commission's investment standards set out in this title, or other type of acceptable agreement with an entity whose operations are regulated and examined by a federal or State agency.

(2) A PGC may satisfy the state assurance obligation by obtaining a written guarantee or financial support agreement from a direct or higher-tier parent corporation or a corporation with a substantial business relationship with the PGC or by meeting the following standards itself. The guarantee or financial support agreement must be payable to the PGC decommissioning trust. The parent or supporting corporation, or PGC must meet one of the following standards:

(A) The parent or supporting corporation, or PGC must have:

(i) Tangible net worth of at least 10 times the state assurance amount, excluding the net book value of the nuclear units subject to the state assurance obligation;

(ii) Tangible net worth of at least $500 million;

(iii) Net working capital of at least 10 times the annual decommissioning funding amount; and

(iv) Assets located in the United States amounting to at least 90% of the total assets or at least 10 times the state assurance amount.

(B) The parent or supporting corporation, or PGC must be otherwise financially qualified, based upon a finding by the commission that there is reasonable assurance that the parent or supporting corporation will be able to meet its obligations under the guarantee or other agreement.

(3) A PGC may satisfy the state assurance obligation by providing an adequate surety, insurance, or other guarantee method that meets the following minimum requirements:

(A) A guarantee that the state assurance obligation will be paid to the PGC decommissioning trust upon any default by the PGC in satisfying its annual funding obligation.

(B) A surety method may be in the form of a surety bond, letter of credit, or line of credit. Any surety method or insurance used to satisfy the state assurance obligation must contain the following conditions:

(i) The surety method or insurance must be open-ended, or, if written for a specified term, such as five years, must be renewed automatically, unless 90 days or more prior to the renewal day the issuer notifies the commission and the PGC of its intention not to renew. The surety or insurance must also provide that the full face amount will be paid to the PGC decommissioning trust automatically prior to the expiration without proof of forfeiture if the PGC fails to provide a replacement acceptable to the commission within 30 days after receipt of notification of cancellation.

(ii) The issuer must have a minimum rating of A- by Standard and Poor's Corporation, A3 by Moody's Investor's Service or the equivalent rating from A.M. Best.

(iii) The surety or insurance must be payable to the PGC decommissioning trust.

(4) A PGC may satisfy the state assurance obligation using any other method acceptable to the commission considering the relative risk factors and creditworthiness attributes of the applicant's financial characteristics to minimize exposure of retail electric customers to default by power generation companies.

(5) A PGC shall notify the commission within 10 days of the date of any material change in its ability to meet its state assurance obligation and provide a plan to cure any deficiency if the material change results in a PGC's inability to meet the state assurance obligation. Upon receipt of such notice, the commission may initiate a formal proceeding to review the PGC's ability to meet the state assurance obligation, or take any other action it deems appropriate. The PGC shall provide any information required to conduct the review in accordance with the commission's procedural rules.

(l) **Annual Funding Obligation**. A PGC using a PGC decommissioning trust shall remit annually to the fund the most recent annual decommissioning funding amount required by the commission. A PGC shall make periodic payments according to a schedule submitted to the commission and shall notify the trustee of the decommissioning trust and the commission within 10 days of the date of any failure to make a scheduled payment. The commission shall not consider a PGC to be in default of its annual funding obligation unless it fails to remit the necessary amounts within 60 days of notice of potential default. If a PGC is in default of its annual funding obligation, it shall notify the trustee of the decommissioning trust and the commission within 10 days of the date of the default. If the PGC fails to cure its failure to make scheduled payment within 60 days of the commission notice, the commission may direct the trustee to request that any entity providing state assurance remit annually to the fund the most recent annual decommissioning funding amount required by the commission in accordance with the schedule approved by the commission, including any payments that the PGC has failed to make, until the PGC is not in default or until the assurance is depleted.

(m) **Funding Shortfall and Unspent Funds.**

(1) If the PGC fails to meet its annual funding requirements and if the state assurance obligations are insufficient to meet the annual funding obligations or are otherwise not honored, the commission shall determine the manner in which any shortfall in the cost of decommissioning a nuclear generating unit shall be recovered from retail electric customers in the state. For retail electric customers of a municipally-owned utility or an electric cooperative that has an agreement to purchase power from a nuclear generating unit, the amount of the shortfall in the cost of decommissioning the nuclear generating unit that the customers are responsible for is limited to a portion of that shortfall that bears the same proportion to the total shortfall as the amount of electric power generated by the nuclear generating unit and purchased by the municipally-owned utility or electric cooperative bears to the total amount of power generated by the nuclear generating unit.

(2) Decommissioning funds that remain unspent after decommissioning of the nuclear generating unit is complete shall be returned to the PGC and the retail electric customers based on the proportionate amount, in real terms, that the PGC and retail electric customers paid into the fund.

(3) While the nuclear generating unit is operational, as a condition of operating the generating unit, the PGC or any new owner shall repay the costs the electric customers incurred in a manner determined by the commission. The PGC shall be responsible for accounting for the need for repayment of any decommissioning shortfall amounts paid by customers and shall report such amounts pursuant to subsection (g) of this section. The PGC shall submit a proposal to repay shortfall amounts paid by customers pursuant to subsection (h) of this section. The commission shall review this information using the procedure described in subsection (e) of this section.

(n) **Administration of the PGC Decommissioning Trust Funds.**

(1) The PGC shall assure that the PGC decommissioning trust is managed so that the funds are secure and earn a reasonable return; and that the funds provided from the PGC's operating revenues, plus the amounts earned from investment of the funds, will be available at the time of decommissioning.

(2) The PGC shall appoint an institutional trustee and may appoint one or more investment managers. Unless otherwise specified in this section, the Texas Trust Code controls the administration and management of the PGC decommissioning trusts, except that the appointed trustees need not be qualified to exercise trust powers in Texas.

(3) The PGC shall retain the right to replace the trustee with or without cause. In appointing a trustee, the PGC shall have the following duties, which will be of a continuing nature:

(A) A duty to determine whether the trustee's fee schedule for administering the trust is reasonable, when compared to other institutional trustees rendering similar services, and meets the requirement of this section;

(B) A duty to investigate and determine whether the past administration of trusts by the trustee has been reasonable;

(C) A duty to investigate and determine whether the financial stability and strength of the trustee is adequate;

(D) A duty to investigate and determine whether the trustee has complied with the trust agreement and this section as it relates to trustees; and

(E) A duty to investigate any other factors that may bear on whether the trustee is suitable.

(4) The PGC shall retain the right to replace the investment manager with or without cause. In appointing an investment manager, the PGC shall have the following duties, which will be of a continuing nature:

(A) A duty to determine whether the investment manager's fee schedule for investment management services is reasonable, when compared to other such managers, and meets the requirement of this section;

(B) A duty to investigate and determine whether the past performance of the investment manager in managing investments has been reasonable;

(C) A duty to investigate and determine whether the financial stability and strength of the investment manager is adequate for purposes of liability;

(D) A duty to investigate and determine whether the investment manager has complied with the investment management agreement and this section as it relates to investments; and

(E) A duty to investigate any other factors which may bear on whether the investment manager is suitable.

(5) The PGC shall execute an agreement with the institutional trustee. The agreement shall be consistent with this section and may include additional restrictions on the trustee. A PGC shall not grant the trustee powers that are greater than those provided to trustees under the Texas Trust Code or that are inconsistent with the limitations of this section. The agreement shall include the restrictions set forth in this section and may include additional restrictions on the trustee.

(A) The interest or other earnings of the trust become part of the trust corpus.

(B) A trustee owes the same duties with regard to the interest and other earnings of the trust as are owed with regard to the corpus of the trust.

(C) A trustee shall have a continuing duty to review the trust portfolio for compliance with investment guidelines and governing regulations.

(D) A trustee shall not lend funds from the PGC decommissioning trust to itself, its officers, or its directors.

(E) A trustee shall not invest or reinvest PGC decommissioning trusts in instruments issued by the trustee, except for time deposits, demand deposits, or money market accounts of the trustee. However, investments of a PGC decommissioning trust may include mutual funds that contain securities issued by the trustee if the securities of the trustee constitute no more than 5% of the fair market value of the assets of such mutual funds at the time of the investment.

(F) The agreement shall comply with all applicable requirements of the federal Nuclear Regulatory Commission.

(6) The PGC shall execute an agreement with the investment manager. If the trustee performs investment management functions, the contractual provisions governing those functions must be included in either the trust agreement or a separate investment management agreement. A PGC shall not grant the manager powers that are greater than those provided to trustees under the Texas Trust Code or that are inconsistent with the limitations of this section. The agreement shall include the restrictions set forth in this section and may include additional restrictions on the manager.

(A) An investment manager shall, in investing and reinvesting the funds in the trust, comply with this section.

(B) The interest and other earnings of the trust become part of the trust corpus.

(C) An investment manager owes the same duties with regard to the interest and other earnings of the trust as are owed with regard to the corpus of the trust.

(D) An investment manager shall have a continuing duty to review the trust portfolio to determine the appropriateness of the investments.

(E) An investment manager shall not invest funds from the PGC decommissioning trust with itself, its officers, or its directors.

(F) The agreement shall comply with all applicable requirements of the federal Nuclear Regulatory Commission.

(7) Prior to executing an amended agreement with the institutional trustee or investment managers, the proposed amended agreement shall be filed at the commission for review along with a redlined version showing all changes made since the document was reviewed by the commission, and copies shall be provided to the commission's Legal Division and Rate Regulation Division or successor divisions.

(8) A copy of the trust agreement, any investment management agreement, and any amendments shall be filed with the commission within 30 days after the execution or modification of the agreement, and copies shall be provided to appropriate commission staff and the Office of Public Utility Counsel.

(o) **Trust investments.**

(1) The funds in a PGC decommissioning trust should be invested consistent with the following goals. The PGC may apply additional prudent investment goals to the funds so long as they are not inconsistent with the stated goals of this subsection.

(A) The funds should be invested with a goal of earning a reasonable return commensurate with the need to preserve the value of the assets of the trusts.

(B) In keeping with prudent investment practices, the portfolio of securities held in the PGC decommissioning trust shall be diversified to the extent reasonably feasible given the size of the trust.

(C) Asset allocation and the acceptable risk level of the portfolio should take into account market conditions, the time horizon remaining before the commencement and completion of decommissioning, and the funding status of the trust. While maintaining an acceptable risk level consistent with the goal in this section, the investment emphasis when the remaining life of the liability exceeds five years should be to maximize net long-term earnings. The investment emphasis in the remaining investment period of the trust should be on current income and the preservation of the fund's assets.

(D) In selecting investments, the impact of the investment on the portfolio's volatility and expected return net of fees, commissions, expenses and taxes should be considered.

(2) The following requirements shall apply to all PGC decommissioning trusts under this section. Where a PGC has multiple trusts for a single generating unit, the restrictions contained in this subsection apply to all trusts in the aggregate for that generating unit. For purposes of this section, a commingled fund is defined as a professionally managed investment fund of fixed-income or equity securities established by an investment company regulated by the Securities Exchange Commission or a bank regulated by the Office of the Comptroller of the Currency.

(A) The total trustee and investment manager fees paid on an annual basis by the PGC for the entire portfolio including commingled funds shall not exceed 0.7% of the entire portfolio's average annual balance.

(B) For the purpose of this subsection, a commingled or mutual fund is not considered a security; rather, the diversification standard applies to all securities, including the individual securities held in commingled or mutual funds. Once the portfolio of securities (including commingled funds) held in the PGC decommissioning trusts contains securities with an aggregate value in excess of $20 million, it shall be diversified such that:

(i) no more than 5.0% of the securities held may be issued by one entity, with the exception of the federal government, its agencies and instrumentalities, and

(ii) the portfolio shall contain at least 20 different issues of securities. Municipal securities and real estate investments shall be diversified as to geographic region.

(C) The PGC may invest the decommissioning funds by means of qualified or unqualified PGC decommissioning trusts; however, the PGC shall, to the extent permitted by the Internal Revenue Service, invest its decommissioning funds in "qualified" PGC decommissioning trusts, in accordance with the Internal Revenue Service Code §468A. The PGC shall avoid, whenever possible, the investment of taxable decommissioning funds in "unqualified" PGC decommissioning trusts.

(D) The use of derivative securities in the trust is limited to those whose purpose is to enhance returns of the trust without a corresponding increase in risk or to reduce risk of the portfolio. Derivatives may not be used to increase the value of the portfolio by any amount greater than the value of the underlying securities. Prohibited derivative securities include, but are not limited to, mortgage strips; inverse floating rate securities; leveraged investments or internally leveraged securities; residual and support tranches of Collateralized Mortgage Obligations; tiered index bonds or other structured notes whose return characteristics are tied to non-market events; uncovered call/put options; large counter-party risk through over-the-counter options, forwards and swaps; and instruments with similar high-risk characteristics.

(E) The use of leverage (borrowing) to purchase securities or the purchase of securities on margin for the trust is prohibited.

(F) The following investment limits shall apply to the percentage of the aggregate market value of all non-fixed income investments relative to the total portfolio market value.

(i) Except as noted in clause (ii) of this subparagraph, when the weighted average remaining life of the liability exceeds five years, the equity cap is 60%;

(ii) When the weighted average remaining life of the liability ranges between five years and 2.5 years, the equity cap shall be 30%;

(iii) When the weighted average remaining life of the liability is less than 2.5 years, the equity cap shall be 0%. Additionally, during all years in which expenditures for decommissioning the nuclear units occur, the equity cap shall also be 0%;

(iv) For purposes of this subsection, the weighted average remaining life in any given year is defined as the weighted average of years between the given year and the years of each decommissioning outlay, where the weights are based on each year's expected decommissioning expenditures divided by the amount of the remaining liability in that year; and

(v) Should the market value of non-fixed income investments, measured monthly, exceed the appropriate cap due to market fluctuations, the PGC shall, as soon as practicable, reduce the market value of the non-fixed income investments below the cap. Such reductions may be accomplished by investing all future contributions to the fund in debt securities as is necessary to reduce the market value of the non-fixed income investments below the cap, or if prudent, by the sale of equity securities.

(vi) A PGC decommissioning trust shall not invest in securities issued by the PGC collecting the funds or any of its affiliates or any company providing security for the state assurance obligation; however, investments of a PGC decommissioning trust may include commingled funds that contain securities issued by the PGC if the securities of the PGC constitute no more than 5.0% of the fair market value of the assets of such commingled funds at the time of the investment.

(3) The following restrictions shall apply to all PGC decommissioning trusts. Where a PGC has multiple trusts for a single generating unit, the restrictions contained in this subsection apply to all trusts in the aggregate for that generating unit.

(A) A PGC decommissioning trust shall not invest trust funds in corporate or municipal debt securities that have a bond rating below investment grade (below “BBB-” by Standard and Poor’s Corporation or “Baa3” by Moody’s Investor’s Service) at the time that the securities are purchased and shall reexamine the appropriateness of continuing to hold a particular debt security if the debt rating of the company in question falls below investment grade at any time after the debt security has been purchased. Commingled funds may contain some below investment grade bonds; however, the overall portfolio of debt instruments shall have a quality level, measured quarterly, that is not below a “AA” grade by Standard and Poor’s Corporation or “Aa2” by Moody’s Investor’s Service. In calculating the quality of the overall portfolio, debt securities issued by the federal government shall be considered as having a “AAA” rating.

(B) At least 70% of the aggregate market value of the equity portfolio, including the individual securities in commingled funds, shall have a quality ranking from a major rating service such as the earnings and dividend ranking for common stock by Standard and Poor’s or the quality rating of Ford Investor Services. Further, the overall portfolio of ranked equities shall have a weighted average quality rating equivalent to the composite rating of the Standard and Poor’s 500 index, assuming equal weighting of each ranked security in the index. If the quality rating, measured quarterly, falls below the minimum quality standard, the PGC shall as soon as practicable and prudent to do so, increase the quality level of the equity portfolio to the required level. A PGC decommissioning trust shall not invest in equity securities where the issuer has a capitalization of less than $100 million.

(C) The following guidelines shall apply to the investments made through commingled funds. Examples of commingled funds appropriate for investment by PGC decommissioning trusts include equity-indexed funds, actively managed equity funds, balanced funds, bond funds, and real estate investment trusts.

(i) The commingled funds should be selected consistent with the goals of this section.

(ii) In evaluating the appropriateness of a particular commingled fund, the PGC has the following duties, which shall be of a continuing nature:

(I) A duty to determine whether the fund manager’s fee schedule for managing the fund is reasonable, when compared to fee schedules of other such managers;

(II) A duty to investigate and determine whether the past performance of the investment manager in managing the commingled fund has been reasonable relative to prudent investment and PGC decommissioning trust practices and standards; and

(III) A duty to investigate the reasonableness of the net after-tax return and risk of the fund relative to similar funds, and the appropriateness of the fund within the entire PGC decommissioning trust investment portfolio.

(iii) The payment of load fees shall be avoided.

(iv) Commingled funds focused on specific foreign countries, industries, or market sectors or concentrated in a few holdings shall be used only as necessary to balance the trust's overall investment portfolio mix.

§25.311. Competitive Metering Services.

(a) **Purpose.** This section establishes the terms and conditions for competitive metering services to be offered to commercial and industrial customers served by an investor-owned transmission and distribution utility (TDU) beginning on January 1, 2004, as required by Public Utility Regulatory Act (PURA) §39.107(a), in areas where customer choice has been introduced. In areas where customer choice has been delayed, this section shall establish terms and conditions for competitive metering services to begin on a date determined by the commission, following the introduction of customer choice.

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

(1) **Commercial and industrial customers** -- Those customers that do not receive electric service under a residential distribution tariff.

(2) **Data management** -- Includes validation, estimation, editing, extraction of billing components, support of retail transactions described in the Electric Reliability Council of Texas (ERCOT) protocols, and transfer of meter reading data to the settlement agent and other approved entities specified by the ERCOT protocols.

(3) **Maintenance** -- Activities necessary to maintain a meter in proper working order, including failure investigation, equipment repair, and replacement.

(4) **Meter owner** -- Entity that owns the settlement and TDU billing meter that is used for the measurement of electric energy delivered to a particular location.

(5) **Metering services** -- Activities relating to the measurement, for the purpose of settlement and TDU billing, of electricity provided to a retail customer, including, but not limited to ownership, installation and removal, maintenance, testing and calibration, data collection, and data management.

(6) **Meter tampering** -- In areas where competitive metering has been introduced, meter tampering, bypass, or diversion is defined as tampering with a settlement and TDU billing meter or equipment, bypassing the same, or other instances of diversion, such as physically disorienting the meter; attaching objects to the meter to divert or bypass service; inserting objects into the meter; and other electrical and mechanical means of tampering with, bypassing, or diverting electrical service.

(7) **Testing** -- Activities as defined in §25.124 of this title (relating to Meter Testing).

(c) **Meter ownership.** A commercial or industrial retail customer may choose a meter owner. The meter owner may be, at the option of the retail customer:

(1) the retail customer;

(2) a retail electric provider (REP);

(3) the TDU; or

(4) other person authorized by the customer.

(d) **Data ownership.** The current retail customer shall own all meter data related to the premise occupied by that customer, regardless of whether the meter owner is the customer, the owner of the premise, or a third party. A third-party owner of the meter shall have access to the meter data. To the extent that data integrity is not compromised, the current retail customer shall have the right to physical access to the meter to obtain such meter data when technically feasible. The current retail customer shall have the right and capability, including necessary security passwords, to assign access to meter data related to the premise occupied by that customer.

(e) **Metering equipment**.

(1) No later than 60 days after the effective date of this section, ERCOT shall develop a process to establish, and periodically revise, a list of meters that shall be considered qualifying competitive meters for the purposes of this section. Each qualifying competitive meter shall meet commission-approved standards and shall be capable of providing the data necessary for billing in accordance with the TDU's delivery tariff and for settlement in accordance with the settlement agent's protocols.

(2) Requests for installation or removal shall be made to the TDU pursuant to the TDU's tariff.

(f) **Conformance with metering standards.**

(1) A meter that fails to meet commission-approved standards for accuracy shall not be placed in service or left in service. A meter found to violate these standards shall be adjusted or replaced in accordance with this subsection at the time the violation is discovered.

(2) Meters shall be adjusted as closely as practicable to the condition of zero error.

(3) If a meter owned by the TDU is found not to meet commission-approved standards for accuracy, the TDU shall install a replacement meter in accordance with its tariffs.

(4) If a meter that is not owned by the TDU is found not to meet commission-approved standards for accuracy, the TDU shall install a temporary replacement meter. The temporary replacement meter shall be capable of providing the data necessary for billing in accordance with the TDU's tariff, and shall also provide settlement data in accordance with the settlement agent's protocols. The TDU shall notify the customer and the meter owner that the meter does not meet commission-approved standards for accuracy and shall take reasonable measures to safeguard the meter until the meter owner takes possession of it. The meter owner shall be responsible for the associated charges, in accordance with the TDU's tariff.

(g) **Testing of meters.** Costs for meter tests requested by the customer, REP, competitive meter owner, or TDU shall be the responsibility of the requesting party in accordance with the TDU's tariff, except that when a request is made to test a meter that is subsequently found not to meet commission-approved standards for accuracy, the cost of the meter test shall be the responsibility of the meter owner.

(1) Upon request for a meter test by a retail customer, a REP shall request that a meter be tested in accordance with the TDU's applicable tariff.

(2) A REP may request that a meter be tested in accordance with the TDU's applicable tariff.

(3) A meter owner other than the retail customer may request that a meter be tested in accordance with the TDU's applicable tariff.

(4) If the TDU suspects a meter malfunction, it shall promptly test the meter in accordance with its tariff.

(5) Following the completion of any meter test, the TDU shall promptly advise the requestor, and the retail customer's REP of the date of removal of the meter, the date of the test, the result of the test, and who made the test.

(h) **Use of meter data for settlement and TDU billing.**

(1) Both the TDU and the REP shall have the right and capability, including necessary security passwords, to access meter data for the purpose of rendering a bill, complying with settlement rules of an independent organization, and for load research and load profiling purposes. The TDU is responsible for the security of the data used for settlement and TDU billing and shall maintain the meter programming password capable of altering such billing parameters.

(2) No entity other than the TDU shall have the right, capability, or meter programming password to alter the data collected by the meter for the purpose of TDU billing.

(3) A TDU's requirements for load research shall not have the effect of limiting the type or frequency of meter data available to an end-use customer.

(i) **Competitive metering service credit.** ATDU shall file with the commission a tariff that provides a competitive metering service credit to the REP of a customer that selects a meter owner other than the TDU. Such tariff shall be accompanied by workpapers demonstrating the derivation of the credit.

§25.341. Definitions.

The following words and terms, when used in Division 1 of this subchapter (relating to Unbundling and Market Power), shall have the following meanings, unless the context clearly indicates otherwise:

(1) **Advanced metering** — Includes any metering equipment or services that are not transmission and distribution utility metering system services as defined in this section.

(2) **Additional retail billing services —** Retail billing services necessary for the provision of services as prescribed under Public Utility Regulatory Act (PURA) §39.107(e) but not included in the definition of transmission and distribution utility billing system services under this section.

(3) **Competitive energy services —** Customer energy services business activities that are capable of being provided on a competitive basis in the retail market. Examples of competitive energy services include, but are not limited to the marketing, sale, design, construction, installation, or retrofit, financing, operation and maintenance, warranty and repair of, or consulting with respect to:

(A) energy-consuming, customer-premises equipment;

(B) the provision of energy efficiency services, the control of dispatchable load management services, and other load-management services;

(C) the provision of technical assistance relating to any customer-premises process or device that consumes electricity, including energy audits;

(D) customer- or facility-specific energy efficiency, energy conservation, power quality, and reliability equipment and related diagnostic services provided, however, that this does not include reasonable diagnostic actions by an electric utility when responding to service complaints;

(i) reasonable diagnostic actions include actions necessary to determine if a power quality problem resides with the customer's equipment or with the utility's equipment and to notify the customer that the problem has been attributed to either the utility's equipment or the customer's equipment;

(ii) reasonable diagnostic actions do not include recommendations or actions to correct problems related to equipment on the customer's side of the delivery point that is owned by the customer or by a third-party entity that is not an electric utility;

(E) the provision of anything of value other than tariffed services to trade groups, builders, developers, financial institutions, architects and engineers, landlords, and other persons involved in making decisions relating to investments in energy-consuming equipment or buildings on behalf of the ultimate retail electricity customer;

(F) except as provided in §25.343(f) and (g) of this title (relating to Competitive Energy Services), transformation equipment, power-generation equipment, protection equipment, or other electric apparatus and infrastructure located on the customer's side of the point of delivery that is owned by the customer or by a third-party entity that is not an electric utility. For purposes of this subparagraph, point of delivery means the point at which electric power and energy leave the utility's delivery system;

(G) the provision of information relating to customer usage other than as required for the rendering of a monthly electric bill, including electrical pulse service, provided however that the provision of access to pulses from a meter used to measure electric service for billing in accordance with §25.129 of this title (relating to Pulse Metering), shall not be considered a competitive energy service;

(H) communications services related to any energy service not essential for the retail sale of electricity;

(I) home and property security services;

(J) non-roadway, outdoor security lighting; however, an electric utility may, pursuant to an approved fully unbundled, embedded-cost tariff:
  (i) continue to maintain lighting facilities installed prior to September 1, 2000 and lighting facilities installed as a petitioned service by the utility. Maintenance service includes the installation of replacement lighting fixtures on such lighting facilities; and
  (ii) install and maintain utility-approved lighting fixtures that are owned by and provided to the utility by a retail customer or a retail electric provider, provided that the lighting fixtures are installed on utility-owned poles that are suitable for this purpose;

(K) building or facility design and related engineering services, including building shell construction, renovation or improvement, or analysis and design of energy-related industrial processes;
(L) hedging and risk management services;
(M) propane and other energy-based services;
(N) retail marketing, selling, demonstration, and merchant activities;
(O) facilities operations and management;
(P) controls and other premises energy management systems, environmental control systems, and related services;
(Q) customer-premises energy or fuel storage facilities;
(R) performance contracting (commercial, institutional, and industrial);
(S) indoor air quality products (including, but not limited to air filtration, electronic and electrostatic filters, and humidifiers);
(T) duct sealing and duct cleaning;
(U) air balancing;
(V) customer-premise metering equipment and related services other than as required for the measurement of electric energy necessary for the rendering of a monthly electric bill or to comply with the rules and procedures of an independent organization; and
(W) other activities determined to be a competitive energy service by the commission by rule or order.

(4) **Discretionary service** — Service that is related to, but not essential to, the transmission and distribution of electricity from the point of interconnection of a generation source or third-party electric grid facilities, to the point of interconnection with a retail customer or other third-party facilities. This term also includes emergency services provided by an electric utility on customer facilities pursuant to §25.343(g) of this title.

(5) **Distribution —** For purposes of §25.344(g)(2)(C) of this title (relating to Cost Separation Proceedings), distribution relates to system and discretionary services associated with facilities below 60 kilovolts necessary to transform and move electricity from the point of interconnection of a generation source or third-party electric grid facilities, to the point of interconnection with a retail customer or other third-party facilities, and related processes necessary to perform such transformation and movement. Distribution does not include activities related to transmission and distribution utility billing services, additional billing services, transmission and distribution utility metering services, and transmission and distribution customer services as defined by this section.

(6) **Electrical pulse (or pulse) —** The impulses or signals generated by pulse metering equipment, indicating a finite value, such as energy, registered at a point of delivery as defined in the Tariff for Retail Delivery Service.

(7) **Electrical pulse service** — Use of pulses for any purpose other than for billing, settlement, and system operations and planning.

(8) **Electronic data interchange —** The computer-application-to-computer-application exchange of business information in a standard format.

(9) **Energy service** — As defined in §25.223 of this title (relating to Unbundling of Energy Service).

(10) **Generation —** For purpose of §25.344(g)(2)(A) of this title, generation includes assets, activities, and processes necessary and related to the production of electricity for sale. Generation begins with the acquisition of fuels and their conversion to electricity and ends where the generation company's facilities tie into the facilities of the transmission and distribution system.

(11) **Pulse metering equipment** — Any device, mechanical or electronic, connected to a meter, used to measure electric service for billing, which initiates pulses, the number of which are proportional to the quantity being measured, and which may include external protection devices. Except as otherwise provided in §25.311 of this title (relating to Competitive Metering Services), pulse metering equipment shall be considered advanced metering equipment that shall be owned, installed, operated, and maintained by a transmission and distribution utility and such ownership, installation, operation and maintenance shall not be a competitive energy service.

(12) **Stranded cost charges —** Competition transition charges as defined in §25.5 of this title (relating to Definitions) and transition charges established pursuant to PURA §39.302(7).

(13) **System service —** Service that is essential to the transmission and distribution of electricity from the point of interconnection of a generation source or third-party electric grid facility, to the point of interconnection with a retail customer or other third-party facility. System services include, but are not limited to, the following:

- (A) the regulation and control of electricity in the transmission and distribution system;
- (B) planning, design, construction, operation, maintenance, repair, retirement, or replacement of transmission and distribution facilities, equipment, and protective devices;
- (C) transmission and distribution system voltage and power continuity;
- (D) response to electric delivery problems, including outages, interruptions, and voltage variations, and restoration of service in a timely manner;
- (E) commission-approved public education and safety communication activities specific to transmission and distribution that do not preferentially benefit an affiliate of a utility;
- (F) transmission and distribution utility standard metering and billing services as defined by this section;
- (G) commission-approved administration of energy savings incentive programs in a market-neutral, nondiscriminatory manner, through standard offer programs or limited, targeted market transformation programs; and
- (H) line safety, including tree trimming.

(14) **Transmission —** For purposes of §25.344(g)(2)(B) of this title, transmission relates to system and discretionary services associated with facilities at or above 60 kilovolts necessary to transform and move electricity from the point of interconnection of a generation source or third-party electric grid facilities, to the point of interconnection with distribution, retail customer or other third-party facilities, and related processes necessary to perform such transformation and movement. Transmission does not include activities related to transmission and distribution utility billing system services, additional billing services, transmission and distribution utility metering system services, and transmission and distribution utility customer services as defined by this section.

(15) **Transmission and distribution utility billing system services** — For purposes of §25.344(g)(2)(E) of this title, transmission and distribution utility billing system services relate to the production and remittance of a bill to a retail electric provider for the transmission and distribution charges applicable to the retail electric provider's customers as prescribed by PURA §39.107(d), and billing for wholesale transmission service to entities that qualify for such service. Transmission and distribution utility billing system services may include, but are not limited to, the following:

- (A) generation of billing charges by application of rates to customer's meter readings, as applicable;
- (B) presentation of charges to retail electric providers for the actual services provided and the rendering of bills;
- (C) extension of credit to and collection of payments from retail electric providers;

(D) disbursement of funds collected;
(E) customer account data management;
(F) customer care and call center activities related to billing inquiries from retail electric providers;
(G) administrative activities necessary to maintain retail electric provider billing accounts and records; and
(H) error investigation and resolution.

(16) **Transmission and distribution utility customer services —** For purposes of §25.344(g)(2)(G) of this title, transmission and distribution customer services relate to system and discretionary services associated with the utility's energy efficiency programs, demand-side management programs, public safety advertising, tariff administration, economic development programs, community support, advertising, customer education activities, and any other customer services.

(17) **Transmission and distribution utility metering system services** — For purposes of §25.344 of this title, services that relate to the installation, maintenance, and polling of an end-use customer's standard meter. Transmission and distribution utility metering system services may include, but are not limited to, the following:

(A) ownership of standard meter equipment and meter parts;
(B) storage of standard meters and meter parts not in service;
(C) measurement or estimation of the electricity consumed or demanded by a retail electric consumer during a specified period limited to the customer usage necessary for the rendering of a monthly electric bill;
(D) meter calibration and testing;
(E) meter reading, including non-interval, interval, and remote meter reading;
(F) individual customer outage detection and usage monitoring;
(G) theft detection and prevention;
(H) installation or removal of metering equipment;
(I) the operation of meters and provision of information to an independent organization, as required by its rules and protocols; and
(J) error investigation and re-reads.

§25.342. Electric Business Separation.

(a) **Purpose.** The purpose of this section is to identify the competitive electric industry business activities that must be separated from the regulated transmission and distribution utility and performed by a power generation company (PGC), a retail electric provider (REP), or some other business unit pursuant to the Public Utility Regulatory Act (PURA) §39.051. This section establishes procedures for the separation of such business activities.

(b) **Application.** This section shall apply to electric utilities, as defined in §25.5 of this title (relating to Definitions).

(c) **Compliance and timing.**

(1) The commission shall prescribe a schedule for the filing of a business separation plan prior to the introduction of customer choice for an electric utility that is subject to PURA §39.102(c) or §39.402. Pursuant to such schedule, an affected electric utility shall separate from its regulated utility activities its customer energy services business activities and shall separate its business activities in accordance with subsection (d) of this section.

(2) Upon review of the filing, the commission shall adopt the electric utility's plan for business separation, adopt the plan with changes, or reject the plan and require the electric utility to file a new plan.

(d) **Business separation.**

(1) An electric utility may not offer competitive energy services; however, an electric utility may petition the commission pursuant to §25.343(d) of this title (relating to Competitive Energy Services) for authority to provide to its Texas customers or some subset of its customers any service otherwise identified as a competitive energy service.

(2) Each electric utility shall separate its business activities and related costs into the following units: power generation company; retail electric provider; and transmission and distribution utility company. An electric utility may accomplish this separation either through the creation of separate nonaffiliated companies or separate affiliated companies owned by a common holding company or through the sale of assets to a third party. An electric utility may create separate transmission utility and distribution utility companies.

(3) Each electric utility, subject to PURA §39.157(d), shall comply with this section in a manner that provides for a separation of personnel, information flow, functions, and operations, consistent with PURA §39.157(d) and §25.272 of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates).

(4) All transfers of assets and liabilities to separate affiliated or nonaffiliated companies, a power generation company, retail electric provider, or a transmission and distribution utility company during the initial business separation process shall be recorded at book value.

(5) The commission, in approving a plan under subsection (c) of this section, may prescribe dates for the discontinuation of competitive energy services and the separation of business activities.

(e) **Business separation plans.** Each electric utility subject to PURA §39.051(e) that has not separated its business functions shall file a business separation plan with the commission according to a commission-approved Business Separation Plan Filing Package (BSP-FP) on a date prescribed by the commission. An electric utility for which the commission has previously approved a business separation plan is not required to file an additional plan under this section. If necessary, however, the commission may require such electric utility to file updated information or modifications to its existing business separation plan.

(1) The business separation plan shall include, but shall not be limited to, the following:

(A) A description of the financial and legal aspects of the business separation, the functional and operational separations, physical separation, information systems separation, asset transfers during the initial unbundling, separation of books and records, and compliance with §25.272 of this title both during and after the transition period.

(B) A description of all services provided by the corporate support services company, as well as any corporate support services provided by another separate affiliate including pricing methodologies.

(C) A proposed internal code of conduct that addresses the requirements in §25.272 of this title and the spirit and intent of PURA §39.157. The internal code of conduct shall address each provision of §25.272 of this title, and shall provide detailed rules and procedures, including employee training, enforcement, and provisions for penalties for violations of the internal code of conduct.

(D) A description of each competitive energy service provided within Texas by the electric utility, including a detailed plan for completely and fully separating these competitive energy services, as set forth in §25.343 of this title.

(E) Descriptions of all system services, discretionary services, and other services pursuant to subsection (f) of this section to be provided within Texas by the transmission and distribution utility.

(2) To the extent that not all of the detailed information required to be filed on the date prescribed by the commission is available, the electric utility shall provide a firm schedule for supplemental filings. The commission shall approve only portions of the business separation plan for which complete information is provided.

(f) **Separation of transmission and distribution utility services.**

(1) **Classification of services.** Each service offered, or potentially offered, by a transmission and distribution utility shall be classified as one of the following:

(A) **System service.** The costs associated with providing system service are system-wide costs that are borne by the retail electric provider serving all transmission and distribution customers.

(B) **Discretionary service.**

(i) The cost associated with each discretionary service is customer-specific and should be borne only by the retail electric provider serving the transmission and distribution customer who purchases the discretionary service.

(ii) Each discretionary service shall be provided by the transmission and distribution utility on a nondiscriminatory basis pursuant to a commission-approved embedded cost-based tariff.

(iii) The costs associated with providing discretionary services are tracked separately from costs associated with providing system services.

(iv) A discretionary service is not a competitive energy service as defined by §25.341 of this title (relating to Definitions).

(C) **Petitioned service.** Service in which a petition to provide a specific competitive energy service has been granted by the commission pursuant to §25.343(d)(1) of this title.

(D) **Other service.**

(i) The offering of any other services shall be limited to those services which:

(I) maximize the value of transmission and distribution system service facilities; and

(II) are provided without additional personnel and facilities other than those essential to the provision of transmission and distribution system services.

(ii) If the transmission and distribution utility offers a service under clause (i) of this subparagraph, the transmission and distribution utility shall:

(I) track revenues and to the extent possible the costs for each service separately;

(II) offer the service on a non-discriminatory-basis, and if the commission determines that it is appropriate, pursuant to a commission-approved tariff, and;

(III) credit all revenues received from the offering of this service during the test year after known and measurable adjustments are made to lower the revenue requirement of the transmission and distribution utility on which the rates are based.

(2) **Competitive energy services**. A transmission and distribution utility shall not provide competitive energy services as defined by §25.341 of this title except as permitted pursuant to §25.343 of this title.

§25.343. Competitive Energy Services.

(a) **Purpose.** The purpose of this section is to identify competitive energy services, as defined in §25.341 of this title (relating to Definitions), that shall not be provided by affected electric utilities.

(b) **Application.** This section applies to electric utilities, as defined by the Public Utility Regulatory Act (PURA) §31.002(6), which include transmission and distribution utilities as defined by PURA §31.002(19). This section shall not apply to an electric utility under PURA §39.102(c) until the termination of its rate freeze period. This section shall not apply to an electric utility subject to PURA §39.402 until customer choice begins in the utility's service area.

(c) **Competitive energy service separation.** An electric utility shall not provide competitive energy services, except for the administration of energy efficiency programs as specifically provided elsewhere in this chapter, and except as provided in subsections (f) and (g) of this section.

(d) **Petitions relating to the provision of competitive energy services.**

(1) **Petition by an electric utility to provide a competitive energy service.** A utility may petition the commission to provide on an unbundled-tariffed basis a competitive energy service that is not widely available to customers in an area. The utility has the burden to prove to the commission that the service is not widely available in an area. The utility's petition may be filed jointly with an affected person or with commission staff.

(A) **Review of petition.** In reviewing an electric utility's petition to provide a competitive energy service, the commission may consider, but is not limited to, the following:

(i) geographic and demographic factors;

(ii) number of vendors providing a similar or closely related competitive energy service in the area;

(iii) whether an affiliate of the electric utility offers a similar or closely-related competitive energy service in the area;

(iv) whether the approval of the petition would create or perpetuate a market barrier to entry for new providers of the competitive energy service.

(B) **Petition deemed approved.** A petition shall be deemed approved without further commission action on the effective date specified in the petition if no objection to the petition is filed with the commission and adequate notice has been completed at least 30 days prior to the effective date. The specified effective date must be at least 60 days after the date the petition is filed with the commission. Notice shall be provided to all entities that have requested notice of petitions by filing such request in a project to be established by the commission, to all retail electric providers in Texas that are certified at the time of the petition, and through a newspaper publication once a week for two consecutive weeks in a newspaper in general circulation throughout the service area for which the petition is requested. Such notice shall state in plain language:

(i) the purpose of the petition;

(ii) the competitive energy service that is the subject of the petition; and

(iii) the date on which the petition will be deemed approved if no objection is filed with the commission.

(C) **Approval of petition.**

(i) If a petition under this paragraph is granted, the utility shall provide the petitioned service pursuant to a fully unbundled, embedded cost-based tariff.

(ii) The utility's petition to offer the competitive energy service terminates three years from the date the petition is granted by the commission, unless the commission approves a new petition from the utility to continue providing the competitive energy service.

(iii) The costs associated with providing this service shall be tracked separately from other transmission and distribution utility costs.

(2) **Petition to classify a service as a competitive energy service or to end the designation of a competitive energy service as a petitioned service.** An affected person or the commission staff may petition the commission to classify a service as a competitive energy service or to end the designation of a competitive energy service as a petitioned service. The commission may consider factors including, but not limited to, the factors in paragraph (1) of this subsection (where applicable) when reviewing a petition under this paragraph.

(e) **Filing requirements.**

(1) An electric utility shall file the following as part of its business separation plan pursuant to §25.342 of this title (relating to Electric Business Separation):

(A) descriptions of each competitive energy service provided by the utility;

(B) detailed plans for completely and fully separating competitive energy services; and

(C) petitions, if any, with associated unbundled tariffs to provide a competitive energy service(s) pursuant to subsection (d)(1) of this section. As part of this filing, affected utilities shall provide all supporting workpapers and documents used in the calculation of the charges for the petitioned services.

(2) An electric utility shall file complete cost information related to paragraph (1) of this subsection pursuant to §25.344 of this title (relating to Cost Separation Proceedings) and the Unbundled Cost of Service Rate Filing Package (UCOS-RFP).

(f) **Exceptions related to certain competitive energy services.** An electric utility may not own, operate, maintain or provide other services related to equipment of the type described in §25.341(3)(F) of this title, except in any of the following instances or as otherwise provided in this subchapter or by commission order.

(1) An electric utility may provide equipment, maintenance, and repair services in an emergency situation as set forth in subsection (g) of this section.

(2) An electric utility may provide maintenance service to high-voltage protection equipment and other equipment located on the customer's side of delivery point that is an integral part of the utility's delivery system. For purposes of this subsection, the point of delivery means the point at which electric power and energy leave a utility's delivery system.

(3) An electric utility may own equipment located on the customer's side of the point of delivery that is necessary to support the operation of electric-utility-owned facilities, including, but not limited to, billing metering equipment, batteries and chargers, system protection apparatus and relays, and system control and data acquisition equipment.

(4) Until the earlier of January 1, 2008, or the date the commission grants a petition by an affected person to discontinue facilities-rental service provided by an electric utility under this subsection, an electric utility may, pursuant to a commission-approved tariff, continue to own and lease to a customer distribution-voltage facilities on the customer's side of the point of delivery, if the customer was receiving facilities-rental service under a commission-approved tariff prior to September 1, 2000, and the customer elects to continue to lease the facilities. Facilities-rental service shall be provided in accordance with the following requirements.

(A) If the customer elects to continue to lease the facilities from the electric utility, the customer will retain the options of purchasing the rented facilities, renting additional facilities at that same point of delivery, or terminating the facilities-rental arrangement.

(B) Once all of the facilities formerly leased by the electric utility to the customer have been removed from the customer's side of the point of delivery or have been acquired by the customer, the electric utility may no longer offer facilities-rental service at that point of delivery.

(C) The electric utility may continue to operate and maintain the leased facilities pursuant to a commission-approved tariff.

(D) No later than March 1, 2007, an electric utility that provides facilities-rental service shall file with the commission a report on the status of affected facilities and market conditions for this service. At that time, the electric utility shall also file either a plan to discontinue providing facilities-rental service or a petition pursuant to subsection (d)(1) of this section to continue such service.

(E) An affected person or the commission staff may file a petition under subsection (d)(2) of this section to have facilities-rental service classified as a competitive energy service. If the commission grants such a petition, the affected electric utility shall discontinue facilities-rental service pursuant to a schedule determined by the commission.

(5) An electric utility may operate and maintain a distribution system located behind the electric utility's point of delivery on a military base, whether that distribution system is owned by the military base or a third party. In addition, an electric utility may own such a distribution system. For purposes of this subsection, "point of delivery" means the point at which electric power and energy are metered. The provision of such services by an electric utility shall be considered discretionary services and shall not be considered competitive energy services.

(g) **Emergency provision of certain competitive energy services.**

(1) **Emergency situation.** Notwithstanding subsection (c) of this section, in an emergency situation, an electric utility may provide transformation and protection equipment and transmission and substation repair services on customer facilities. For purposes of this subsection, an "emergency situation" means a situation in which there is a significant risk of harm to the health or safety of a person or damage to the environment. In determining whether to provide the competitive energy service in an emergency situation, the utility shall consider the following criteria:

(A) whether the customer's facilities are impaired or are in jeopardy of failing, and the nature of the health, safety, or environmental hazard that might result from the impairment or failure of the facilities; and

(B) whether the customer has been unable to procure, or is unable to procure within a reasonable time, the necessary transformation and protection equipment or the necessary transmission or substation repair services from a source other than the electric utility.

(C) whether provision of the emergency service to the customer would interfere with the electric utility's ability to meet its system needs.

(2) **Notification and due diligence.** Prior to providing an emergency service as set forth in paragraph (1) of this subsection, the electric utility shall inform the customer that the requested service is a competitive energy service and that the utility is not permitted to provide the service unless it is an emergency situation. The utility must determine, based on information provided from the customer or by other methods, whether the situation is an emergency situation, as defined in paragraph (1) of this section.

(3) **Record keeping and reporting.**

(A) Not later than three business days after the determination of an emergency situation, the electric utility shall attempt to obtain from the customer a written statement explaining the emergency situation and indicating that the customer is aware that the service provided by the utility is a competitive energy service.

(B) The electric utility shall maintain for a period of three years a record of correspondence between the customer and the utility pertaining to the emergency provision of a competitive energy service in accordance with this subsection, including the statement required by subparagraph (A) of this paragraph.

(C) The electric utility shall include in a clearly identified manner the following information for the prior calendar year (January 1 through December 31) in its service quality report filed under §25.81 of this title (relating to Service Quality Reports):

(i) the number of instances in which the utility provided a competitive energy service pursuant to this subsection in the prior calendar year; and

(ii) a brief description of each event, excluding any customer-specific information, and the utility's action to respond to the emergency situation.

(4) **Discretionary service charge for provision of competitive energy services in emergency situation.** The charge for providing service pursuant to this subsection shall be based on a fully unbundled, embedded cost-based discretionary service tariff. An electric utility that seeks to provide emergency service under this subsection shall file with the commission an updated discretionary service rate schedule to implement this subsection. Notwithstanding other provisions in this chapter, an electric utility may directly bill the requesting entity for emergency service provided under this subsection.

(5) **Commission review.** Upon request, an electric utility shall make available to the commission all required records regarding the provision of competitive energy services pursuant to this subsection.

(h) **Evaluation of competitive energy services.** Every two years beginning in October 2005 or as otherwise determined by the commission, the commission shall evaluate the degree of competition for the competitive energy services described in §25.341 of this title to determine if they are widely available in areas throughout Texas.

(i) **Sale of non-roadway security lighting assets.** Prior to the execution of a sale of an electric utility's non-roadway security lighting assets described in §25.341(3)(J)(i) and (ii) of this title, the electric utility shall provide the commission reasonable notice of the proposed transaction.

§25.344. Cost Separation Proceedings.

(a) **Purpose.** The purpose of this section is to establish the procedure by which affected utilities will comply with the Public Utility Regulatory Act (PURA) §39.201.

(b) **Application.** This section shall apply to all utilities subject to PURA §39.201.

(c) **Compliance and timing.**

(1) All electric utilities must file a cost separation case under this section on or before April 1, 2000 according to a unbundled cost of service rate filing package (UCOS-RFP) approved by the commission. Each electric utility shall, in its cost separation filing, file proposed tariffs for its proposed transmission and distribution utility. The filings shall include supporting cost data for the determination of the utility's non-bypassable delivery charges, which shall be the sum of transmission charges, distribution charges, metering system service charges, billing system service charges, customer service system charges (if any), municipal franchise charges, nuclear decommissioning charges (if any), and a competition transition charge (if any).

(2) Notwithstanding any other provision in this section, an electric utility not subject to this section until the expiration of the exemption set forth in PURA §39.102(c), must file its cost separation case on or before 170 days prior to the expiration of the exemption.

(d) **Test year.** A historic test year shall be used to determine a forecast test year, defined as follows:

(1) **Historic year** -- for utilities filing a cost separation case on or before April 1, 2000, the historic year shall be the 12-month period ended September 30, 1999. For a utility filing a cost separation case after April 1, 2000, the historic year shall be a 12-month period deemed reasonable by the commission.

(2) **Forecast year** -- for utilities filing a cost separation case on or before April 1, 2000, the forecast year shall be the projected 12-month period ended December 31, 2002. For a utility filing a cost separation case after April 1, 2000, the forecast year shall be a 12-month period deemed reasonable by the commission.

(e) **Rate of return.** Each electric utility shall file a rate of return that is based on its weighted average cost of capital as determined by one of the alternative methods indicated in the Unbundled Cost of Service Rate Filing Package (UCOS-RFP) approved by the commission.

(f) **Separation of affiliate costs and functional cost separation.**

(1) **Affiliate costs.**

(A) **Separation of affiliate costs.** The affiliate schedules accompanying the UCOS-RFP shall provide sufficient detail to enable the commission to evaluate the necessity and reasonableness of the affiliate expenses and the "no higher than" cost provisions of PURA §36.058 (relating to Consideration of Payment to Affiliate); §25.272 of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates); and §25.273 of this title (relating to Contracts Between Electric Utilities and Their Affiliates). The schedules shall provide the net total amount of affiliate expense requested for each of the historic and forecast years. This information shall be provided by class of items for all affiliate transactions between the transmission and distribution utility and its affiliates including the affiliated power generation company and the affiliated retail electric provider.

(B) **Affiliated service company.** If there is an affiliated service company providing support to the regulated transmission and distribution utility and the other affiliates, then the UCOS-RFP shall include the transactions between the service company, the regulated transmission and distribution utility, the power generation company, the retail electric provider, and all the other affiliates pursuant to PURA §14.154. The UCOS-RFP shall include detailed information on allocation formulas as defined by the reporting schedules.

(C) **Compliance with affiliate rules.** The affiliate transactions reported in the UCOS-RFP shall comply with the code of conduct rules as promulgated in §§25.84 of this title (relating to Annual Reporting of Affiliate Transactions for Electric Utilities), 25.272 of this title, and 25.273 of this title.

(2) **Functional cost separation.** All electric utilities shall separate their costs into nine categories, relating to the following functions, as defined by §25.341 of this title (relating to Definitions):

(A) generation;
(B) transmission;
(C) distribution;
(D) transmission and distribution utility metering system services;
(E) transmission and distribution utility billing system services;
(F) additional retail billing services;
(G) transmission and distribution utility customer service;
(H) competitive energy service; and
(I) other unregulated services.

(3) **Method of cost separation.** Costs shall be assigned to the nine functions using the following three-tier process. No common costs shall be assigned to regulated functions by default. If the utility cannot meet its burden of proof, the costs in question shall be assigned to competitive functions.

(A) For each Federal Energy Regulatory Commission (FERC) account, costs shall be directly assigned to functions to the extent possible, and all relevant workpapers provided.

(B) The utility shall provide detailed workpapers documenting the nature of any costs that cannot be directly assigned. For adequately documented costs, the utility may derive an account-specific functionalization factor based on the directly assigned costs or appropriate cost causation principles. The utility must justify the assignment of common costs to regulated functions, and must present evidence to support any such assignment.

(C) If adequately documented costs remain for which direct assignment or account-specific functionalization cannot be identified, an appropriate functionalization factor as described in the UCOS-RFP may be used. These functionalization factors should only be used as a last resort. If a utility deems a functionalization factor other than the functionalization factor prescribed in the UCOS-RFP to be necessary, the utility shall provide a detailed justification for the chosen functionalization factor.

(g) **Jurisdiction and Texas retail class allocation.** Allocation of each of the functions comprising the transmission and distribution system services revenue requirement to the existing rate classes shall be based on forecasted 2002 test year load data. Costs related to other functions may be allocated based on a test year ending September 30, 1999.

(1) **Jurisdictional allocation.** Functionalized total company costs for the forecast year shall be allocated to the Texas retail jurisdiction. Jurisdictional allocators shall be based on either the methodology approved by the Federal Energy Regulatory Commission (FERC), or the methodology used in the last commission-approved cost of service study.

(2) **Texas retail class allocation.** Total Texas retail jurisdiction costs for each of the nine categories shall be allocated among existing rate classes. Consolidation of classes shall be done only during the rate design process.

(A) **Transmission revenue requirement (system services).** Electric Reliability Council of Texas (ERCOT) utilities shall allocate the total transmission revenue requirement based on the average of the four coincident peaks for each existing rate class at the time of ERCOT peak, if that data is available. If that data is not available, the utility may use the average of the four coincident peaks for each existing rate class at the time of the transmission and distribution utility's system peak. Non-ERCOT utilities shall allocate transmission revenue requirement based on either the FERC-approved methodology or the methodology approved in the last commission-approved cost of service study.

(B) **Distribution revenue requirement (system services).** Costs purely related to demand or customers shall be allocated based on the methodology used in the last cost of service study unless otherwise determined by the commission. Other costs shall be allocated based on allocators analogous to those used during the functionalization process, or appropriate cost-causation principles.

(C) **Generation costs.** Total generation costs shall be allocated to the existing rate classes based on the methodology used to allocate generation costs in the last cost of service study.

(D) **Retail electric provider costs.** Total costs of services which will be provided by the retail electric provider as approved in the business separation plan shall be allocated among classes based on the allocators used in the last cost of service study.

(E) **Decommissioning costs.** Costs associated with nuclear decommissioning obligations shall be allocated based on the methodology used in the last cost of service study unless otherwise approved by the commission. Total costs shall be reported in the unbundled cost of service studies as a separate line item (or subaccount) in each account where such costs occur.

(h) **Determination of ERCOT and Non-ERCOT transmission costs.**

(1) **ERCOT transmission costs.**

(A) The transmission cost of service for an electric utility in ERCOT shall be as described in §25.192(b) of this title (relating to Transmission Service Rates).

(B) The UCOS-RFP adopted by the commission for the cost separation filings shall be used by the electric utilities filing under this section.

(C) Any redirection of transmission depreciation expense to production by an electric utility in ERCOT pursuant to PURA §39.256 should not affect the utility's wholesale transmission cost of service that is used for determining the ERCOT postage stamp rate.

(2) **Non-ERCOT transmission costs.** For an electric utility in Texas operating outside ERCOT, the utility's open access transmission tariff approved by FERC will be used to determine the utility's transmission cost and rates in Texas.

(i) **Rate design.** Utilities shall consolidate existing rate classes into the minimum number of classes needed to recognize differences in usage of the transmission and distribution systems. Class consolidation shall not materially disadvantage any customer class.

§25.345. Recovery of Stranded Costs Through Competition Transition Charge (CTC).

(a) **Purpose.** The purpose of this section is to establish the rules, regulations and procedures by which affected utilities will comply with Public Utility Regulatory Act (PURA), Chapter 39, Subchapter F relating to Recovery of Stranded Costs Through Competition Transition Charge, PURA §39.201, relating to Cost of Service Tariffs and Charges, and PURA, Chapter 39, Subchapter G relating to Securitization in order to establish a competition transition charge (CTC) as a non-bypassable charge.

(b) **Application.** This section shall apply to all electric utilities as defined in PURA §31.002 which have stranded costs as described in PURA §39.251.

(c) **Definitions.** As used in this section, the following terms have the following meanings unless the context clearly indicates otherwise:

(1) **New on-site generation** — Electric generation capacity greater than ten megawatts capable of being lawfully delivered to the site without use of utility distribution or transmission facilities, which was not, on or before December 31, 1999, either:

(A) A fully operational facility, or

(B) A project supported by substantially complete filings for all necessary site-specific environmental permits under the rules of the Texas Natural Resource Conservation Commission (TNRCC) in effect at the time of filing.

(2) **Eligible generation —** Any electric generation facility that falls into one or more of the following categories:

(A) A fully operational qualifying facility that lawfully served a retail customer's load before September 1, 2001, and for which substantially complete filings were made on or before December 31, 1999, for all necessary site-specific environmental permits under the rules of the TNRCC in effect at the time of filing, so long as such facility serves the same end-user it was serving on September 1, 2001.

(B) An on-site power production facility with a rated capacity of ten megawatts or less;

(C) Any generation facility that lawfully served a retail customer's actual load which is capable of lawfully delivering power to the site without use of utility distribution or transmission facilities and which is not new on-site generation including but not limited to facilities described in subparagraphs (A) and (B) of this paragraph, so long as the facility continues to serve the same end-user or users it was serving on December 31, 1999 if it was fully operational at that time or the end-user or users who first took power from the facility when it became operational if it become operational after December 31, 1999.

(d) **Right to recover stranded costs.** An electric utility is allowed to recover all of its net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service. Recovery of retail stranded costs by an electric utility shall be from all existing or future retail customers, including the facilities, premises, and loads of those retail customers, within the utility's geographical certificated service area as it existed on May 1, 1999. A retail customer may not avoid stranded cost recovery charges by switching to on-site generation except as provided by subsection (i) of this section. In multiply certificated areas, a retail customer may not avoid stranded cost recovery charges by switching to another electric utility, electric cooperative, or municipally owned utility after May 1, 1999.

(e) **Recovery of stranded cost from wholesale customers**. Nothing in this section shall alter the rights of utilities to recover wholesale stranded costs from wholesale customers. If the utility decides not to recover some or all stranded costs from its wholesale customers, it shall not recover these costs from retail customers through non-bypassable charges or otherwise.

(f) **Quantification of stranded costs.** An electric utility seeking to recover its stranded costs shall submit the necessary information in compliance with the unbundled cost of service rate filing package (UCOS-RFP) approved by the commission.

(g) **Recovery of stranded costs through securitization.** An electric utility that seeks to recover regulatory assets and stranded costs through securitization financing pursuant to PURA, Chapter 39, Subchapter G shall request a separate competition transition charge for that purpose.

(1) An electric utility that seeks to securitize its regulatory assets or stranded costs pursuant to PURA §39.201(i)(1) shall file an application using the commission-approved form.

(2) An electric utility may seek to securitize its regulatory assets under PURA §39.201(i) any time after September 1, 1999.

(3) An electric utility that seeks to securitize its stranded costs under PURA §39.201(i) must obtain a determination by the commission of its revised estimate of stranded costs prior to submitting its application.

(4) The amount of regulatory assets eligible for securitization as determined by the commission in a proceeding pursuant to §39.201(i)(1) shall be considered in the quantification of stranded costs in subsection (f) of this section.

(h) **Allocation of stranded costs**. Allocation of stranded costs and calculation of CTC per customer class shall be part of the cost separation proceedings as defined in §25.344 of this title (relating to Cost Separation Proceedings). The utility shall submit information in accordance with the instructions contained in the UCOS-RFP.

(1) **Jurisdictional allocation**. Costs shall be allocated to the Texas retail jurisdiction in accordance with the jurisdictional allocation methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design.

(2) **Allocation among Texas customer classes**. Stranded costs shall be allocated in the following manner.

(A) Any capital costs incurred by an electric utility to improve air quality under PURA §39.263 or §39.264 that are included in a utility's invested capital in accordance with those sections shall be allocated among customer classes as follows: 50% of those costs shall be allocated in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design; and the remainder shall be allocated on the basis of the energy consumption of the customer classes.

(B) All other retail stranded costs shall be allocated among retail customer classes in the following manner:

(i) The allocation to the residential class shall be determined by allocating to all customer classes 50% of the stranded costs in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design and allocating the remainder of the stranded costs on the basis of the energy consumption of the classes.

(ii) After the allocation to the residential class required by clause (i) of this subparagraph has been calculated, the remaining stranded costs shall be allocated to the remaining customer classes in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design. Non-firm industrial customers shall be allocated stranded costs equal to 150% of the amount allocated to that class.

(iii) After the allocation to the residential class required by clause (i) of this subparagraph and the allocation to the nonfirm industrial class required by clause (ii) of this subparagraph have been calculated, the remaining stranded costs shall be allocated to the remaining customer classes in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design.

(iv) Notwithstanding any other provision of this section, to the extent that the total retail stranded costs, including regulatory assets, of investor-owned utilities exceed $5 billion on a statewide basis, any stranded costs in excess of $5 billion shall be allocated among retail customer classes in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design.

(v) The energy consumption of the customer classes used in subparagraph (A) of this paragraph and clause (i) of this subparagraph shall be based on the data for the test year ending May 1, 1999 adjusted only for line losses and weather.

(vi) For the rate classes which were not treated as a separate class in the utility's last cost of service study, the generation portion of the base revenues shall be used to develop a demand allocator. For the rate classes that have been determined as discounted rate schedules by the commission, the base revenues used to determine the demand allocator for these rate classes should include imputed revenue.

(i) **Applicability of CTC to customers receiving power from new on-site generation or eligible generation**. A retail customer receiving power from new on-site generation or eligible generation to serve its internal electrical requirements may not avoid payment of stranded costs except as provided in this subsection. A customer's responsibility for payment of stranded costs shall be determined as follows:

(1) **No CTC**. An end-user whose actual load is lawfully served by eligible generation and who does not receive any electrical service that requires the delivery of power through the facilities of a transmission and distribution utility is not responsible for payment of any stranded cost charges.

(2) **CTC for eligible generation.** A retail customer whose actual load is lawfully served by eligible generation who also receives electrical service that requires the delivery of power through the facilities of a transmission and distribution utility shall be responsible for payment of stranded cost charges based solely on the services that are actually provided by the transmission and distribution utility, if any, to the customer after the eligible generation facility became fully operational, such as delivery of supplemental, standby, or backup service. Such charges may not include any costs associated with the service that the customer was receiving from the electric utility or its affiliated transmission and distribution utility under their tariffs before the operation of the eligible generation. A customer who changes the type of service received from the electric utility or its affiliated transmission and distribution utility after the customer commences taking energy from eligible generation will pay stranded cost charges associated with the service it is actually receiving from the transmission and distribution utility.

(3) **CTC for new on-site generation.** A retail customer who commences taking power from new on-site generation that represents a material reduction in the customer's use of energy delivered through the utility's facilities shall be responsible for payment of stranded cost charges that are calculated by multiplying the output of the new on-site generation utilized to meet the internal electrical requirements of the customer each month by the sum of the applicable stranded cost charges in effect for that month. The applicable CTC for such customer shall be the CTC associated with the service that the customer was receiving from the electric utility prior to switching to new on-site generation. These stranded cost charges shall be paid in addition to the stranded cost charges applicable to energy actually delivered to the customer through the transmission and distribution utility's facilities. A customer who commences taking power from new on-site generation that does not represent a material reduction in the customer's use of energy delivered through the transmission and distribution utility's facilities shall pay the CTC calculated as set forth in paragraph (2) of this subsection for that portion of the customer's load served by the new on-site generation.

(4) **Material reduction.** For purposes of this subsection, a material reduction shall be a reduction of 12.5% or more of the retail customer's use of energy delivered through the utility's transmission and

distribution facilities. The reduction shall be calculated by comparing the customer's monthly use of energy attributable to new on-site generation to the customer's average monthly use of energy delivered through the utility's facilities for the 12-month period immediately preceding the date on which the customer commenced taking energy from the new on-site generation.

(5) **Multiple on-site power production facilities.** A retail customer may designate any number of on-site power production facilities located on a single site as eligible generation under subsection (c)(2)(B) of this section as long as the sum of rated capacities of such facilities does not exceed ten megawatts. Stranded cost charges for any on-site power production facility with a rated capacity of ten megawatts or less, not designated as eligible generation under this paragraph, shall be calculated in accordance with the methodology set forth in paragraph (3) of this subsection for new-on-site generation that results in a material reduction in the retail customer's use of energy delivered through the utility's transmission and distribution facilities. For purposes of determining whether the installation of multiple on-site power production facilities under this paragraph has caused a material reduction in the customer's use of energy under paragraph (4) of this subsection, all of the energy delivered to the customer from such facilities will be taken into account. A customer may not create separate entities on a single site for the purpose of gaining exemptions under this paragraph. A retail customer may change the designation of such an on-site power production facility**:**

(A) No sooner than one year after the facility's initial designation;

(B) No sooner than one year after the facility's subsequent designation; or

(C) Upon addition or retirement of any such on-site power production facility being used to serve the customer's load.

(6) **Reporting requirements.** Persons owning or operating new on-site generation or eligible on-site generation shall submit the information required by §25.105 of this title (relating to Registration and Reporting by Power Marketers, Exempt Wholesale Generators, and Qualifying Facilities). Those persons shall also comply with procedures and reporting requirements described in the transmission and distribution utility's tariffs related to the assignment and collection of the CTC from eligible and new on-site generation and any other commission rule or regulation related to the implementation of this section.

(7) **Adjustment to overall CTC.** On and after January 1, 2005, the commission will periodically review the overall allocation of the CTC among customers and/or customer classes to incorporate the loss of contribution due to customers taking advantage of the specific statutorily granted exceptions under this section and adjust the charges prospectively. To the extent these are known and measurable at the time of the April 2000 filing, sufficient information shall be provided by the filing utility to allow for calculation of the CTC.

(j) **Collection and rate design of CTC charges**. These charges shall be billed to a customer's retail electric provider. The CTC shall recover the amount of stranded costs as defined in PURA, Chapter 39, Subchapter F that are reasonably projected to exist on the last day of the freeze period. Utilities shall consolidate existing rate classes into the minimum number of classes needed to sufficiently recognize differences in usage of the underlying generation assets. Customers shall be classified into no fewer than the following classes: Residential, Commercial, Firm Industrial, Non-firm, and Back-up Service. No customer classes shall be materially disadvantaged by class consolidation.

§25.346. Separation of Electric Utility Metering and Billing Service Costs and Activities.

(a) **Purpose.** The purpose of this section is to identify and separate electric utility metering and billing service activities and costs for the purposes of unbundling.

(b) **Application.** This section shall apply to electric utilities as defined in Public Utility Regulatory Act (PURA) §31.002 in areas where customer choice is in effect.

(c) **Separation of transmission and distribution utility billing system service costs.**

(1) Transmission and distribution utility billing system services shall include costs related to the billing services described in §25.341(15) of this title (relating to Definitions).

(2) Charges for transmission and distribution utility billing system services shall not include any additional capital costs, operation and maintenance expenses, and any other expenses associated with billing services as prescribed by PURA §39.107(e).

(d) **Separation of transmission and distribution utility billing system service activities.**

(1) Transmission and distribution utility billing system services as defined in §25.341 of this title shall be provided by the transmission and distribution utility.

(2) The transmission and distribution utility may provide additional retail billing services pursuant to PURA §39.107(e).

(3) Additional retail billing services pursuant to PURA §39.107(e) shall be provided on an unbundled discretionary basis pursuant to a commission-approved embedded cost-based tariff.

(4) The transmission and distribution utility may not directly bill an end-use retail customer for services that the transmission and distribution utility provides except when the billing is incidental to providing retail billing services at the request of a retail electric provider pursuant to PURA §39.107(e).

(e) **Uncollectibles and customer deposits.**

(1) The retail electric provider is responsible for collection of its charges from retail customers and measures to secure payment.

(2) For the purposes of functional cost separation in §25.344 of this title (relating to Cost Separation Proceedings), retail customer uncollectibles and deposits shall be assigned to the unregulated function, as prescribed by §25.344(g)(2)(I) of this title.

(f) **Separation of transmission and distribution utility metering system service costs.** Transmission and distribution utility metering system services shall include costs related to the transmission and distribution utility metering system services as defined in §25.341 of this title.

(g) **Separation of transmission and distribution utility metering system service activities.**

(1) Prior to the introduction of customer choice, metering service shall be provided in accordance with Subchapter F of this chapter (relating to Metering). An electric utility shall continue to provide metering services pursuant to commission rules and regulations, but shall not engage in the provision of competitive energy services as defined by §25.341 of this title and prescribed by §25.343 of this title (relating to Competitive Energy Services).

(2) On the introduction of customer choice in a service area, metering services as described by §25.341(17) of this title for the area shall continue to be provided by the transmission and distribution utility affiliate (or successor in interest) of the electric utility that was serving the area before the introduction of customer choice, but the transmission and distribution utility shall not

engage in the provision of competitive energy services as defined by §25.341 of this title and prescribed by §25.343 of this title.

(A) Standard meter service shall be provided in accordance with this subparagraph. Advanced meter service shall be provided in accordance with §25.130 of this title (relating to Advanced Metering).

(i) The standard meter shall be owned, installed, and maintained by the transmission and distribution utility except as prescribed by §25.311 of this title (relating to Competitive Metering Services).

(ii) The transmission and distribution utility shall bill a retail electric provider for non-bypassable charges based upon the measurements obtained from each end-use customer's standard meter.

(iii) If the retail electric provider requests the replacement of the standard meter with an advanced meter, the transmission and distribution utility shall charge the retail electric provider the incremental cost for the replacement of the standard meter with an advanced meter owned, operated, and maintained by the transmission and distribution utility.

(iv) Without authorization from the retail electric provider, the transmission and distribution utility's use of advanced meter data shall be limited to that energy usage information necessary for the calculation of transmission and distribution charges in accordance with that end-use customer's transmission and distribution rate schedule.

(B) Nothing in this section precludes the retail electric provider from accessing the transmission and distribution utility's standard meter for the purposes of determining an end-use customer's energy usage.

(C) Nothing in this section precludes the end-use customer or the retail electric provider from owning, installing, and maintaining metering equipment in addition to the standard meter.

(h) **Competitive energy services.**

(1) Nothing in this section is intended to affect the provision of competitive energy services, including those that require access to the customer's meter.

(2) An electric utility shall not provide any service that is deemed a competitive energy service under §25.341 of this title except as provided under §25.343 of this title.

(i) **Electronic data interchange.**

(1) All transmission and distribution utilities, retail electric providers, power generation companies, power marketers, and electric utilities shall transmit data in accordance with standards and procedures adopted by the commission or the independent organization.

(2) All transmission and distribution utilities, retail electric providers, power generation companies, power marketers, and electric utilities shall abide by the settlement procedures adopted by the commission or the independent organization.

(3) Transmission and distribution utilities shall be allowed to recover such costs as prudently incurred in abiding by this subsection, to the extent not collected elsewhere, such as through the administrative fee of an independent organization.

§25.361. Electric Reliability Council of Texas (ERCOT).

(a) **Applicability.** This section applies to the Electric Reliability Council of Texas (ERCOT). It also applies to transmission service providers (TSPs) and transmission service customers, as defined in §25.5 of this title (relating to Definitions), with respect to interactions with ERCOT. For the purpose of this section and §25.362 of this title (relating to Electric Reliability Council of Texas (ERCOT) Governance), an ERCOT rule is a market protocol, operating guide, market guide, or other procedure that constitutes a statement of general policy and that has an impact on the governance of the organization or on reliability, settlement, customer registration, or access to the transmission system in the ERCOT region.

(b) **Functions.** ERCOT shall perform the functions of an independent organization under the Public Utility Regulatory Act (PURA) §39.151 to ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms; ensure the reliability and adequacy of the regional electrical network; ensure that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to the persons who need that information; and ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region. ERCOT shall:

(1) administer, on a daily basis, the operational and market functions of the ERCOT system, including procuring and deploying ancillary services, scheduling resources and loads, and managing transmission congestion, as set forth in this chapter, commission orders, and ERCOT rules;

(2) administer settlement and billing for services provided by ERCOT, including assessing creditworthiness of market participants and establishing and enforcing reasonable security requirements in relation to their responsibilities under ERCOT rules;

(3) serve as the single point of contact for the initiation of transmission services;

(4) maintain the reliability and security of the ERCOT region's electrical network, including the instantaneous balancing of ERCOT generation and load and monitoring the adequacy of resources to meet demand;

(5) provide for non-discriminatory access to the transmission system, consistent with this chapter, commission orders, and ERCOT rules;

(6) accept and supervise the processing of all requests for interconnection to the ERCOT transmission system from owners of new generating facilities;

(7) coordinate and schedule planned transmission facility outages;

(8) perform system screening security studies, with the assistance of affected TSPs;

(9) plan the ERCOT transmission system, in accordance with this section;

(10) establish and administer procedures for the registration of market participants;

(11) manage and operate the customer registration system;

(12) administer the renewable energy program, unless the commission designates a different person to administer the program;

(13) monitor generation planned outages;

(14) disseminate information relating to market operations, market prices, and the availability of services, in accordance with this chapter, commission orders, and the ERCOT rules;

(15) operate an electronic transmission information network; and

(16) perform any additional duties required under this chapter, commission orders, and ERCOT rules.

(c) **Liability**. ERCOT shall not be liable in damages for any act or event that is beyond its control and which could not be reasonably anticipated and prevented through the use of reasonable measures, including, but not limited to, an act of God, act of the public enemy, war, insurrection, riot, fire, explosion, labor disturbance or strike, wildlife, unavoidable accident, equipment or material shortage, breakdown or accident to machinery or equipment, or good faith compliance with a then valid curtailment, order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities.

(d) **Planning.** ERCOT shall conduct transmission system planning and exercise comprehensive authority over the planning of bulk transmission projects that affect the transfer capability of the ERCOT transmission system. ERCOT shall supervise and coordinate the other planning activities of TSPs.

(1) ERCOT shall evaluate and make a recommendation to the commission as to the need for any transmission facility over which it has comprehensive transmission planning authority.

(2) A TSP shall coordinate its transmission planning efforts with those of other TSPs, insofar as its transmission plans affect other TSPs.

(3) ERCOT shall submit to the commission any revisions or additions to the planning guidelines and procedures prior to adoption. ERCOT may seek input from the commission as to the content and implementation of its guidelines and procedures as it deems necessary.

(e) **Information and coordination**. Transmission service providers and transmission service customers shall provide such information as may be required by ERCOT to carry out the functions prescribed by this chapter, commission orders, and ERCOT rules. ERCOT shall maintain the confidentiality of competitively sensitive information and other protected information, as specified in §25.362 of this title. Providers of transmission and ancillary services shall maintain the confidentiality of competitively sensitive information entrusted to them by ERCOT or a transmission service customer.

(f) **Interconnection standards**. ERCOT may prescribe reliability and security standards for the interconnection of generating facilities that use the ERCOT transmission network. Such standards shall not adversely affect or impede manufacturing or other internal process operations associated with such generating facilities, except to the minimum extent necessary to assure reliability of the ERCOT transmission network.

(g) **ERCOT administrative fee**. ERCOT shall charge an administrative fee, and the fees it charges are subject to commission approval, in accordance with this chapter.

(h) **Reports.** Each TSP and transmission service customer in the ERCOT region shall on an annual basis provide to ERCOT historical information concerning peak loads and resources connected to the TSP's system.

(i) **Anti-trust laws.** The existence of ERCOT is not intended to affect the application of any state or federal anti-trust laws.

(j) **Decertification.** ERCOT shall be subject to decertification as an independent organization in accordance with §25.364 of this title (relating to Decertification of an Independent Organization).

(k) **Pilot Projects.**

(1) ERCOT may conduct pilot projects to provide a temporary platform to evaluate resources, technologies, services, and processes that demonstrate the potential to advance the operational and market functions of the ERCOT system. The pilot projects will allow ERCOT to validate performance claims of alternative technologies, evaluate the extent to which new technologies or

processes can provide services that comply with federal and state reliability standards, and review how resources perform in various operational and market scenarios. As part of a pilot project, ERCOT may grant temporary exceptions from ERCOT rules, as necessary to effectuate the purposes of the pilot project. ERCOT may use information gained from pilot projects to inform the development of permanent changes to ERCOT rules.

(2) Process for Development and Approval of Pilot Projects. ERCOT may conduct a pilot project upon approval of the scope and purposes of the pilot project by the governing board of ERCOT. Proposals for approval of pilot projects shall be made to the governing board only by ERCOT staff, after consultation with affected market participants and commission staff designated by the executive director. The ERCOT governing board shall ensure that there is an opportunity for adequate stakeholder review and comment on any proposed pilot project. Pilot project proposals approved by the ERCOT governing board shall include:

(A) The scope and purposes of the pilot project;

(B) Designation of temporary exceptions from ERCOT rules that ERCOT expects to authorize as part of the pilot project;

(C) Criteria and reporting mechanisms to determine whether and when ERCOT should propose changes to ERCOT rules based upon results of a pilot project;

(D) An estimate of costs ERCOT will incur attributable to the pilot project; and

(E) An estimated date of completion for the pilot project.

(3) Participation in a pilot project shall not be required as a condition to the deployment of any resource, technology, or process that complies with existing ERCOT rules. The existence of a pilot project does not prohibit any market participant from proposing changes to ERCOT rules that are not dependent on the outcome of the pilot project.

(4) A decision of the ERCOT governing board approving a pilot project pursuant to this subsection constitutes “ERCOT conduct” for purposes of appeal to the commission pursuant to §22.251 of this title (relating to Review of Electric Reliability Council of Texas (ERCOT) Conduct).

§25.362. Electric Reliability Council of Texas (ERCOT) Governance.

(a) **Purpose.** This section provides standards for the governance of an independent organization within the ERCOT region.

(b) **Application.** This section applies to ERCOT or any other organization within the ERCOT region that qualifies as an independent organization under PURA §39.151.

(c) **Adoption of rules by ERCOT and commission review.** ERCOT shall adopt and comply with procedures concerning the adoption and revision of ERCOT rules.

(1) The procedures shall provide for advance notice to interested persons, an opportunity to file written comments or participate in public discussions, and, in the case of market protocols, operating guides, planning guides, and market guides, an evaluation by ERCOT of the costs and benefits to the organization and the operation of electricity markets.

(2) ERCOT staff, the independent market monitor, and the commission's reliability monitor may comment on any proposed change in ERCOT rules that affects the operation and competitiveness of markets operated by ERCOT or reliability of the electric network in ERCOT.

(3) If the findings of a commission-mandated audit of ERCOT operations or governance indicate the need for a change in operating practices or procedures or governance rules, ERCOT shall develop and submit to the commission a plan for implementing the changes. ERCOT shall implement the plan, as approved by the commission. Commission-mandated audits, as contemplated in PURA §39.151(d) and (d-1), shall be funded by ERCOT and do not require approval by the governing board of ERCOT.

(4) The commission may review a provision of ERCOT's articles of incorporation or by-laws, or a new or amended ERCOT rule on the application of an interested person, including commission staff and the Office of Public Utility Counsel.

(5) The commission shall process requests for review of a provision of ERCOT's articles of incorporation or by-laws, a new or amended ERCOT rule, or ERCOT decision in accordance with §22.251 of this title (relating to Review of Electric Reliability Council of Texas (ERCOT) Conduct). A request for review under this subsection initiated by the commission, commission staff, or the Office of Public Utility Counsel is not subject to the alternative dispute resolution requirements in §22.251(c) of this title, which requires the use of Section 20 of the ERCOT Protocols (Alternative Dispute Resolution Procedures), Section 21 of the Protocols (Process for Protocol Revision), or other applicable ERCOT procedures. In addition, the commission may, for good cause, waive the requirement that a complaint be filed within the time prescribed in §22.251(d) of this title.

(d) **Access to meetings.** ERCOT shall adopt and comply with procedures for providing access to its meetings to market participants and the general public. These procedures shall include provisions on advance notice of the time, place, and topics to be discussed during open and closed portions of the meetings, and making and retaining a record of the meetings. Records of meetings of the governing board shall be retained permanently, and ERCOT shall establish reasonable retention periods, but not less than five years, for records of other meetings.

(e) **Access to information.** This subsection governs access to information held by ERCOT.

(1) ERCOT shall adopt and comply with procedures that allow persons to request and obtain access to records that ERCOT has or has access to relating to the governance and budget of the organization, market operations, reliability, settlement, customer registration, and access to the transmission system. ERCOT shall make these procedures publicly available. Information that is

available for public disclosure pursuant to ERCOT procedures shall normally be provided within ten business days of the receipt of a request for the information. If a response requires more than ten business days, ERCOT shall notify the requester of the expected delay and the anticipated date that the information may be available. ERCOT's procedures regarding access to records shall be consistent with this chapter and commission orders.

(A) Information submitted to or collected by ERCOT pursuant to requirements of ERCOT rules shall be protected from public disclosure only if it is designated as Protected Information pursuant to ERCOT rules, except as otherwise provided in this subsection.

(B) ERCOT shall promptly respond to a request from the commission, a commissioner, a commissioner's designee, the commission executive director, or the executive director's designee for information that ERCOT collects, creates or maintains, in order to provide the commission access to information that the commission, a commissioner, a commissioner's designee, the executive director, or the executive director's designee determines is necessary to carry out the commission's responsibilities for oversight of ERCOT and the wholesale and retail markets.

(C) In the absence of a request for information under the Texas Public Information Act, Texas Government Code Annotated, the commission staff may seek to release information that the commission has in its possession or has access to that has been designated as Protected Information under ERCOT rules, and the commission may determine the validity of the asserted claim of confidentiality through a contested-case proceeding. In a contested-case proceeding conducted by the commission pursuant to this subsection, the staff, the entity that provided the information to the commission, and ERCOT will have an opportunity to present information or comment to the commission on whether the information is subject to protection from disclosure under law.

(D) In connection with any challenge to the confidentiality of information under subparagraph (C) of this paragraph, any person who asserts a claim of confidentiality with respect to the information must, at a minimum, state in writing the specific reasons why the information is subject to protection from public disclosure and provide legal authority in support of the assertion.

(2) Commission employees, consultants, agents, and attorneys who have access to Protected Information pursuant to this section shall not disclose such information except as provided in the Texas Public Information Act.

(f) **Conflicts of interest.** ERCOT shall adopt policies to ensure that its operations are not affected by conflicts of interests relating to its employees' outside employment and financial interests and its contractors' relationships with other businesses. These policies shall include an obligation to protect confidential information obtained by virtue of employment or a business relationship with ERCOT.

(g) **Qualifications, selection, and removal of members of the governing board.** ERCOT shall establish and implement criteria for an individual to serve as a member of its governing board, procedures to determine whether an individual meets these criteria, and procedures for removal of an individual from service if the individual ceases to meet the criteria.

(1) The qualification criteria shall include:

(A) Definitions of the market sectors;

(B) Levels of activity in the electricity business in the ERCOT region that an organization in a market sector must meet, in order for a representative of the organization to serve as a member of the governing board;

(C) Standards of good standing that an organization must meet, in order for a representative of the organization to serve as a member of the governing board; and

(D) Standards of good standing that an individual must meet, in order for the individual to serve as a member of the governing board.

(2) The procedures for removal of a member from service on the governing board shall include:

(A) Procedures for determining whether an organization or individual meets the criteria adopted under paragraph (1) of this subsection; and

(B) Procedures for the removal of an individual from the governing board if the individual or the organization that the individual represents no longer meets the criteria adopted under paragraph (1) of this subsection or violates an ERCOT rule, including a written ERCOT policy adopted under this section, or commission rule, or applicable statute.

(3) The procedures adopted under paragraph (2) of this subsection shall:

(A) Permit any interested party to present information that relates to whether an individual or organization meets the criteria specified in paragraph (1) of this subsection or has violated an ERCOT rule, including a written ERCOT policy adopted under this section, or commission rule, or applicable statute; and

(B) Specify how decisions concerning the qualification of an individual or whether an individual has violated an ERCOT rule or written ERCOT policy or procedure adopted under this section, or commission rule, or applicable statute will be made.

(4) A decision concerning an individual or organization's qualification or an individual's removal from the governing board is subject to review by the commission.

(5) ERCOT shall notify the commissioners when a vacancy occurs for an unaffiliated member of the governing board. ERCOT shall provide information to the commissioners concerning the process for selecting a new member, the candidates who have been identified and their qualifications, any recommendation that will be made to the governing board, and any other information requested by a commissioner. The selection of an unaffiliated member of the governing board is subject to approval by the commission. A person who is selected may not serve as a member of the governing board until the commission approves the selection. An unaffiliated board member whose three-year term has expired shall, if reappointed by the ERCOT governing board, cease serving as a member of the governing board until the reappointment is approved by the commission. The commission may remove an unaffiliated member of the governing board for cause. Compensation, per diem and travel reimbursements to be paid to unaffiliated members of the governing board shall be subject to commission review and approval. As used in this paragraph, "cause" shall mean:

(A) a violation of a commission rule or applicable statute, an ERCOT rule, or written ERCOT policy or procedure adopted under this section;

(B) a director is indicted or charged with a felony or is convicted of a misdemeanor involving moral turpitude;

(C) conduct inconsistent with a director's fiduciary duty to ERCOT or that may reflect poorly upon the board or ERCOT; or

(D) a fundamental disagreement with the commission as to the policies or procedures that ERCOT shall adopt, in each case as determined by the commission at its sole discretion.

(6) A member of the governing board of ERCOT appointed after the effective date of this paragraph who serves as an unaffiliated member may not represent a market participant before the governing board of ERCOT, the ERCOT technical advisory committee, or any of its subcommittees or working groups, for a period of one year after the person ceases to serve as a member of the governing board.

(h) **Chief executive officer.** The appointment of the chief executive officer of ERCOT is subject to commission approval. ERCOT shall notify the commissioners when a vacancy occurs for the chief executive officer. ERCOT shall provide information to the commissioners concerning the process for selecting a new chief executive officer, the candidates who have been identified and their qualifications, any recommendation that will be made to the governing board, and any other information requested by a commissioner. A person may not seek the position of the ERCOT chief executive officer while serving as a commissioner. Compensation to be paid to the ERCOT chief executive officer shall be subject to commission review and approval.

(i) **Required reports and other information.** ERCOT shall file with the commission the reports and provide the information required by this subsection.

(1) **The qualification criteria shall include:**

(A) Definitions of the market sectors;

(B) Levels of activity in the electricity business in the ERCOT region that an organization in a market sector must meet, in order for a representative of the organization to serve as a member of the governing board;

(C) Standards of good standing that an organization must meet, in order for a representative of the organization to serve as a member of the governing board; and

(D) Standards of good standing that an individual must meet, in order for the individual to serve as a member of the governing board.

(2) **Operations report and plan.** No later than January 15 of each year, ERCOT shall file an operations report and plan. The commission may initiate a review of the plan, at its discretion. The report and plan shall contain the following information:

(A) A copy of an independent audit of ERCOT's market operation for the report year;

(B) A summary of key market operations statistics, including prices and quantities of energy and capacity purchased in the markets operated by ERCOT;

(C) A summary of key reliability statistics;

(D) A summary of transmission planning and generation interconnection activities and the most recent report on capacity, demand and reserves;

(E) A description of ERCOT's roles and responsibilities within the electric market in Texas, including system reliability, operation of energy and capacity markets, managing transmission congestion, transmission planning and interconnection of new generating plants, and a description of how ERCOT's roles and responsibilities relate to the roles and responsibilities of the transmission and distribution utilities and retail electric providers and to the North American Electric Reliability Corporation and Texas Reliability Entity;

(F) A risk management plan that identifies any significant risks to system reliability, the operation of ERCOT's energy and capacity markets, its management of transmission congestion, and any other risks that would significantly disrupt the sale and delivery of electricity within the ERCOT region, and the measures that might be taken to mitigate such risks;

(G) An emergency communications plan that describes how ERCOT will communicate with the public, media, governmental entities, and market participants concerning events that affect the bulk electric system;

(H) An assessment of the reliability and adequacy of the ERCOT system during extremely cold or extremely hot weather conditions, or drought, for which purpose ERCOT has the right, upon reasonable notice, to conduct generator site visits to review compliance with weatherization plans and has the right to obtain from generators any information concerning water supplies for generation purposes, including contracts, water rights, and other information; and

(I) Identification of existing and potential transmission constraints, and the need for additional transmission, generation or demand response resources within the ERCOT region. The report shall include projections of changes in demand, the capability of generation, energy storage, and demand response resources, projected reserve margins, alternatives for meeting system needs, and recommendations for meeting system needs.

(3) **Quarterly reports.** ERCOT shall file quarterly reports no later than 45 days after the end of each quarter, which shall include:

(A) Any internal audit reports that were produced during the reporting quarter;

(B) A report on performance measures, as prescribed by the commission;

(C) By account item as established in the fee-filing package prescribed by the commission under §22.252 of this title (relating to Procedures for Approval of ERCOT Fees and Rates) a report of:

(i) ERCOT fees and other rates, funds allocated, funds encumbered, and funds expended;

(ii) An explanation for expenditures deviating from the original funding allocation for the particular account item;

(iii) For the report covering the fourth quarter of ERCOT's fiscal year, a detailed explanation of how unexpended funds will be expended in the subsequent year; and

(D) Any other information the commission may deem necessary.

(4) **Emergency reports.** If ERCOT management becomes aware of any event or situation that could reasonably be anticipated to adversely affect the reliability of the regional electric network; the operation or competitiveness of the ERCOT market; ERCOT's performance of activities related to the customer registration function; or the public's confidence in the ERCOT market or in ERCOT's performance of its duties, ERCOT management shall immediately notify the chairman of the commission, or the chairman's designee, and the executive director of the commission, or the executive director's designee, by telephone. Additionally, ERCOT shall file a written report of the facts involved by the end of the following business day after becoming aware of such event or situation, unless the executive director specifies, in writing, that the report may be delayed. The executive director may not authorize a delay of more than 30 days for filing the required written report. For good cause, the commission may grant further delays in filing the required report. If it determines that additional reports are necessary, the commission may establish a schedule for the filing of additional reports after the initial written report by ERCOT. As a part of any additional written report, ERCOT may be required to fully explain the facts and to disclose any actions it has taken, or will take, in order to prevent a recurrence of the events that led to the need for filing an emergency report.

(5) **Meeting Periodicity Report.** Beginning with the effective date of this section, ERCOT shall recommend annually to the commission the periodicity of governing board meetings. ERCOT's recommendation shall be based on an examination of the frequency of meetings conducted by similar organizations and shall include an estimate of the costs associated with meeting more frequently than once per quarter.

(j) **Compliance with rules or orders.** ERCOT shall inform the commission with as much advance notice as is practical if ERCOT realizes that it will not be able to comply with PURA, any provision of this chapter, or a commission order. If ERCOT fails to comply with PURA, any provision of this chapter, or a commission order, the commission may, after notice and opportunity for hearing, adopt the measures specified in this subsection or such other measures as it determines are appropriate.

(1) The commission may require ERCOT to submit, for commission approval, a proposal that details the actions ERCOT will undertake to remedy the non-compliance.

(2) The commission may require ERCOT to begin submitting reports, in a form and at a frequency determined by the commission, that demonstrate ERCOT's current performance in the areas of non-compliance.

(3) The commission may require ERCOT to undergo an audit performed by an appropriate independent third party.

(4) The commission may assess administrative penalties under PURA Chapter 15, Subchapter B.

(5) The commission may suspend or revoke ERCOT's certification under PURA §39.151(c) or deny a request for change in the terms associated with such certification.

(6) Nothing in this section shall preclude any form of civil relief that may be available under federal or state law.

(k) **Priority of commission rules.** This section supersedes any protocols or procedures adopted by ERCOT that conflict with the provisions of this section. The adoption of this section does not affect the validity of any rule or procedure adopted or any action taken by ERCOT prior to the adoption of this section.

§25.363. ERCOT Budget and Fees.

(a) **Scope.** This section applies to the budget of and all fees and rates levied or charged by the Electric Reliability Council of Texas (ERCOT) in its role as an independent organization under PURA §39.151.

- (1) A fee or rate that was in effect on the effective date of this section shall remain in effect and shall not be changed, except as provided in this section.
- (2) ERCOT shall not implement any new or modified budget, rate or fee without commission approval, except as otherwise provided by this section.
- (3) ERCOT shall not incur expenses or capital outlays in any year that exceed the amounts approved by the commission, except in the case of an emergency that impairs its ability to conduct is functions.
- (4) ERCOT shall not incur debt, defer scheduled principal repayments of debt, or refinance existing debt without commission approval. ERCOT shall seek approval of any loan or agreement to provide a line of credit from a bank or other institution, the issuance of bonds or notes, and any arrangements that would permit it to issue bonds or permit the issuance of bonds on its behalf at a later date. The commission may approve, disapprove, or modify a proposal made pursuant to this paragraph. This paragraph does not require approval of a contract to lease equipment or other property used in normal operations, approval of a loan or draw on an existing line of credit or other credit arrangement that has been approved by the commission, or renewal of an existing working capital line of credit that has been approved by the commission.

(b) **System of accounts and reporting.** For the purpose of accounting and reporting to the commission, ERCOT shall maintain its books and records in accordance with Generally Accepted Accounting Principles. ERCOT shall establish a standard chart of accounts and employ it consistently from year to year. The standard chart of accounts shall be used for the purpose of reporting to the commission and shall be consistent with the long-term operations plan prescribed by §25.362 of this title (relating to Electric Reliability Council of Texas (ERCOT) Governance). The accounts shall show all revenues resulting from the various fees charged by ERCOT and reflect all expenses in a manner that allows the commission to determine the sources of the costs incurred for each major activity conducted by ERCOT.

(c) **Allowable expenses.** Expenses and capital outlays in the budget shall be based upon ERCOT's expected cost of performing its required functions as described in PURA §39.151(a) and this chapter. To determine whether the costs are reasonable and necessary, the commission may consider the budget justification provided by ERCOT, the ERCOT long-term operations plan, costs incurred by market participants and other independent system operators for similar activities, costs incurred in prior years, capital projects identified in the budget, and to any other information and data considered appropriate by the commission.

- (1) Only those expenses that are reasonable and necessary to carry out the functions described in PURA §39.151 and this chapter shall be included in allowable expenses.
- (2) Allowable expenses, to the extent they are reasonable and necessary, may include, but are not limited to, the following general categories:
  - (A) Operating expenses, which include salaries and related benefits, direct advertising for the specific purpose of recruiting employees, legal and consulting services, hardware and software maintenance and licensing, insurance, employee training and travel, and depreciation;
  - (B) Facility and equipment costs, and other long-lived investments;
  - (C) Debt service (interest plus principal reduction) and other reasonable and necessary costs of capital to fund investments in property and facilities, and other capital expenditures that are used and useful in performing the functions of an independent organization;

(D) Expenses associated with fees and dues charged by organizations setting electric or energy business practices and communications standards (*e.g.,* North American Electric Reliability Council, North American Energy Standards Board, and ISO/RTO Council) of which ERCOT is a member; and

(E) Actual expenditures for public service announcements and community education efforts.

(3) The following are not allowable as a component of expenses:

(A) Legislative advocacy expenses, whether made directly or indirectly;

(B) Funds expended in support of political candidates, movements or causes;

(C) Funds expended promoting religious causes;

(D) Funds expended in support of or in acquiring membership in social, recreational, or fraternal clubs or organizations;

(E) Funds expended for advertising, marketing, or other promotions, which includes, but is not limited to:

(i) promotional goods;

(ii) efforts to increase name recognition;

(iii) radio, television, newspaper or other media advertising; except as otherwise expressly authorized; and

(F) Any expenditure found by the commission to be unreasonable, unnecessary, not in the public interest, or not sufficiently supported by the fee-filing package and accompanying evidence.

(d) **Budget Submission.** ERCOT shall submit its proposed budget for commission review as specified in the commission order approving its previous budget. As part of its application for approval of its proposed budget, ERCOT shall include all information necessary for the commission to evaluate the proposed budget, including all information required under this section. The commission shall provide public notice of ERCOT's proposed budget and allow a reasonable opportunity for the public to comment on the ERCOT's proposed budget. The review and approval of a proposed budget or a proceeding to authorize and set the range for the amount of the fee under this section is not a contested case for purposes of Chapter 2001 of the Texas Government Code.

(e) **Commission review and action.** The ERCOT annual budget and any change in the system administration fee are subject to review by the commission either annually or biennially, at the commission's discretion. Prior to the submission of a proposed budget or change in the system administration fee to the governing board for its approval, ERCOT shall consult with commission staff designated by the executive director in connection with the development of the budget and shall provide to the staff information concerning budget strategies, staffing requirements, categories of expenses, capital outlays, exceptional expenses and capital items, and proposals to incur additional debt. ERCOT shall file with the commission its board-approved budget, budget strategies, and staffing needs, with a justification for all expenses, capital outlays, additional debt, and staffing requirements. The commission may approve, disapprove, or modify any item included in the proposed budget and budget strategies. After approving ERCOT's budget, the commission shall authorize ERCOT to charge a system administration fee, within a range determined by the commission, that is reasonable and competitively neutral to fund ERCOT's budget. ERCOT shall closely match actual revenues generated by the system administration fee and other sources of revenue with revenue necessary to fund the budget, taking into account the effect of a fee change on market participants and consumers, to ensure that the budget year does not end with a surplus or insufficient funds. Any change to the fee approved by the commission or made during the course of an annual or biennial budget cycle will be noticed through standard market processes at least 45 days before implementation. ERCOT shall file with the commission, upon request, a report comparing actual expenditures with budgeted expenditures. Such reports shall be filed at least once per year.

(f) **Performance measures.** ERCOT shall develop proposed performance measures to track its operations. Such measures shall be submitted for commission review and approval at the time ERCOT submits its proposed budget. ERCOT shall provide an explanation for any performance measure whose value for any of the preceding three calendar years was not within 5% of the commission-approved target. The commission will review ERCOT's performance as part of the budget review process. The commission shall prepare a report evaluating ERCOT's performance at the time the commission approves ERCOT's budget and shall submit the report to the Lieutenant Governor, the Speaker of the House of Representatives, and each house and senate standing committee that has jurisdiction over electric utility issues.

(g) **User Fees.** ERCOT may charge reasonable user fees for services provided by ERCOT to any market participant or other entity. User fees do not include the system administration fee and the ERCOT nodal implementation surcharge. A new or revised user fee may be approved by the ERCOT governing board. Any affected entity, including the commission staff and the public counsel, may file an appeal of the establishment or revision of a user fee, in accordance with §22.251 of this title (relating to Review of Electric Reliability Council of Texas (ERCOT) Conduct), except that the provisions of §22.251(c) of this title (which requires the use of Section 20 of the ERCOT Protocols (Alternative Dispute Resolution Procedures), or Section 21 of the Protocols (Process for Protocol Revision), or other Applicable ERCOT Procedures) shall not apply.

§25.364. Decertification of an Independent Organization.

(a) **Purpose**. This section establishes the procedures for the decertification of an independent organization and the transfer of assets to a successor organization pursuant to Public Utility Regulatory Act (PURA) §39.151(d).

(b) **Applicability**. This section applies to any organization that the commission has certified as an independent organization pursuant to PURA §39.151.

(c) **Initiation of proceeding to decertify**. The commission may initiate a proceeding to revoke an independent organization's certification. Prior to initiating a proceeding to revoke a certification, the commission may conduct an audit or study of the performance of an independent organization with respect to its efficiency and effectiveness in carrying out the duties of an independent organization under PURA and this title. Any such audit or study may be conducted or supervised by the commission and shall be funded by the independent organization.

(d) **Standard for decertification**. The commission may issue an order decertifying an independent organization if it finds that the organization has committed significant violations of PURA or commission rules or failed to efficiently and effectively carry out the duties of an independent organization.

(e) **Order revoking certification**. The commission's order revoking certification shall ensure continuity of operations of the independent organization and shall designate the successor organization that will assume the functions of the independent organization. The commission order revoking certification will provide for the independent organization to transfer its assets and liabilities to the successor independent organization designated by the commission.

(f) **Selection of successor organization**. Prior to the decertification of an independent organization, the commission shall designate, and certify pursuant to PURA §39.151(c), a successor independent organization from among persons that have submitted proposals in response to the commission's request. To the extent that there are duties performed by the current independent organization that are not required by statute, organizations other than a successor independent organization may be designated to assume those functions.

(g) **Transfer of assets**. The transfer of assets and liabilities from a decertified independent organization to its successor organization shall be made in a way that ensures that the functions of the independent organization continue to be provided reliably and without interruption. The commission may impose specific conditions or requirements upon the transfer of assets and liabilities.

(h) **Continuity of operations**. To ensure that all of the required functions of the independent organization continue to be carried out during the decertification and transfer process, the commission, upon its own initiative, may order the independent organization or its successor organization, or both, to perform or continue certain acts related to the organization's operation. These include, but are not limited to, capital investment projects, financing, meeting or renegotiating contractual obligations, and employment of essential personnel.

§25.365. Independent Market Monitor.

(a) **Purpose**. The purpose of this section is to define the responsibilities and authority of the independent market monitor (IMM) for the ERCOT wholesale markets, establish the standards for funding the IMM, specify the staffing requirements and qualifications for the IMM, and establish ethics standards for the IMM. This section also specifies the relationship of the IMM to the commission, to ERCOT, and to market participants. The IMM shall operate under the commission's supervision and oversight, but the IMM shall offer independent analysis to the commission to assist in making judgments in the public interest.

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

(1) **Independent Market Monitor (IMM)** — Depending on the context, the office of the IMM or the director of the IMM and its staff.

(2) **Market** — The course of commercial activity by which the exchange of goods or services is effected. As used in this section, the term may refer to an entire market or a portion of a market.

(3) **Market participant** — Any person or entity participating in the power region's wholesale markets, or engaging in any activity that is in whole or in part the subject of the ERCOT protocols, regardless of whether the person or entity has executed an agreement with ERCOT. This definition includes, but is not limited to, a load-serving entity (including a municipally-owned utility and an electric cooperative), a retail electric provider, a qualified scheduling entity, a power marketer, a transmission and distribution utility, a power generation company, a qualifying facility, an exempt wholesale generator, a load acting as a resource, and any entity conducting planning, scheduling, or operating activities on behalf of such market participants.

(c) **Objectives of market monitoring.** The IMM shall monitor wholesale market activities so as to:

(1) Detect and prevent market manipulation strategies and market power abuses; and

(2) Evaluate the operations of the wholesale market and the current market rules and proposed changes to the market rules, and recommend measures to enhance market efficiency.

(d) **Responsibilities of the IMM.** The IMM shall gather and analyze information and data as needed for its market monitoring activities. The duties and responsibilities of the IMM may include:

(1) Monitoring all markets in the power region for energy, capacity services, and congestion revenue rights, and the ERCOT protocols and related procedures and practices that affect supply, demand, and the efficient functioning of such markets;

(2) Developing and regularly monitoring market screens and indices to identify abnormal events in the power region's wholesale markets;

(3) Analyzing events that fail the screens and other abnormal activities and market events, using computer simulation and advanced quantitative tools as necessary;

(4) Developing and regularly monitoring performance measures to evaluate market participants' and ERCOT's compliance with the ERCOT protocols and operating guides;

(5) Assessing the effectiveness of ERCOT's management of the energy, ancillary capacity services, and congestion rights markets operated by ERCOT, and evaluating the effectiveness of congestion management by ERCOT;

(6) Conducting market power tests and other analyses related to market power determination;

(7) Analyzing the ERCOT protocols and other market rules and proposed changes to those rules to identify opportunities for strategic manipulation and other economic inefficiencies, as well as potential areas of improvement;

(8) Conducting investigations of specific market events;

(9) Providing expert testimony services relating to the IMM's independent analysis, findings, and expertise, as part of the commission staff's case in enforcement proceedings initiated by the executive director in accordance with §22.246 of this title (relating to Administrative Penalties) or other commission proceedings;

(10) Maintaining a market oversight website to share market information with the public;

(11) Preparing market monitoring reports as required under subsection (k) of this section;

(12) Recommending to the commission measures to enhance the efficiency of the wholesale market and methods to correct market design flaws it has identified; and

(13) Performing any additional duties required by the commission within the scope of the Public Utility Regulatory Act §39.1515.

(e) **Authority of the IMM.**

(1) The IMM has the authority to conduct monitoring, analysis, reporting, and related activities but has no enforcement authority.

(2) The IMM has the authority to question a market participant about activities that may violate commission rules or ERCOT protocols or may be potential market manipulations. The IMM may inform a market participant that its activities may be in violation of commission rules or ERCOT protocols or operating guides, subject to the restrictions established by subsection (j)(2) of this section.

(3) The IMM has the authority to require submission of any information and data it considers necessary to fulfill its monitoring and investigative responsibilities by ERCOT and by market participants. Market participants and ERCOT shall provide complete, accurate, and timely responses to all IMM requests for documents, data, information, and other materials.

(4) The IMM may require that each market participant designate one or more points of contact that can answer questions the IMM may have regarding a market participant's operations or market activities.

(f) **Selection of the IMM.** ERCOT and the commission shall contract with an entity selected by the commission to act as the commission's wholesale market monitor. The IMM shall be established as an office independent from ERCOT, and is not subject to the supervision of ERCOT with respect to its monitoring and investigative activities.

(g) **Funding of the IMM.** The budget and expenditures of the IMM are subject to commission supervision and oversight. Financial controls and reporting procedures shall be implemented by the IMM and ERCOT to ensure that expenditures are consistent with the budget that was approved by the commission, and with this section.

(1) ERCOT shall fund the operations of the IMM using money from the rate authorized by PURA §39.151.

(2) The funding of the IMM shall be sufficient to ensure that the IMM has the resources and expertise necessary to monitor the wholesale electric market effectively, as determined by the commission.

(3) ERCOT shall maintain separate accounts of expenditures in support of the IMM.

(4) ERCOT shall directly assign costs arising from the IMM function to the IMM whenever possible. To the extent overhead and shared expenses cannot be directly assigned, ERCOT shall allocate such expenses to the IMM based on appropriate cost causation factors. ERCOT shall maintain all records and work papers necessary to substantiate all direct charges and allocations to the IMM.

(h) **Staffing requirements and qualification of IMM director and staff.**

(1) The director of the IMM shall have the qualifications necessary to oversee performance of the duties and responsibilities in subsection (c) of this section. The staff of the IMM shall have the

qualifications needed to perform the market monitoring functions in subsection (c) of this section. The IMM director and staff shall be subject to background security checks as determined by the commission.

(2) The staff of the IMM shall collectively possess a set of technical skills necessary to perform market monitoring functions, which typically includes economics, with a focus on market analysis and market competitiveness; power engineering; statistics and programming; and modeling, with a focus on optimization modeling.

(i) **Ethics standards governing the IMM director and staff.**

(1) During the period of a person's service with the IMM, the IMM director and an IMM employee shall not:

(A) have a professional or financial interest in a market participant or an affiliate of a market participant; or own shares in a company that provides consulting services to a market participant;

(B) serve as an officer, director, partner, owner, employee, attorney, or consultant for ERCOT or a market participant or an affiliate of a market participant;

(C) directly or indirectly own or control securities in a market participant, an affiliate of a market participant, or direct competitor of a market participant or affiliate, except that it is not a violation of this rule if the IMM director or an IMM employee indirectly owns an interest in a retirement system, institution or fund that in the normal course of business invests in diverse securities independently of the control of the IMM director or employee; or

(D) accept a gift, gratuity, or entertainment from ERCOT, a market participant, affiliate of a market participant, or an employee or agent of a market participant or affiliate of a market participant.

(2) The IMM director or an IMM employee shall not directly or indirectly solicit, request from, suggest, or recommend to a market participant or affiliate of a market participant, or an employee or agent of a market participant or affiliate of a market participant, the employment of a person by a market participant or affiliate.

(3) The commission may impose post employment restrictions for the IMM and its employees.

(j) **Confidentiality standards governing the IMM director and staff.**

(1) The IMM shall protect confidential information and data in accordance with the confidentiality standards established in PURA, the ERCOT protocols, commission rules, and other applicable laws. The requirements related to the level of protection to be afforded information protected by these laws and rules are incorporated in this section.

(2) Unless otherwise notified by the commission legal staff, the IMM may not communicate with a market participant or with an ERCOT board member, officer, or employee, or with any other entity concerning a particular subject matter once the commission legal staff notifies the IMM that the subject matter is the subject of an investigation or enforcement proceeding.

(k) **Reporting requirement.** All reports prepared by the IMM shall reflect the IMM's independent analysis, findings, and expertise. The IMM shall provide periodic updates to market participants regarding the operation of the ERCOT wholesale market. In addition, the IMM shall prepare and submit to the commission the following reports:

(1) Daily, monthly, and quarterly reports on prices and congestion;

(2) An annual report on the state of the market, which will include an assessment of the competitiveness of the market; an assessment of the efficiency of ERCOT's management of the balancing energy, ancillary services, and congestion rights markets; an evaluation of the

effectiveness of congestion management by ERCOT; an evaluation of whether there are inappropriate incentives, flaws, inefficiencies, and opportunities for manipulation in the market design; and any recommendations for improving the market design; and

(3) Periodic or special reports on market conditions or specific events as directed by the commission.

(l) **Communication between the IMM and the commission.**

(1) The personnel of the IMM may communicate with commission staff on any matter without restriction.

(2) The IMM shall:

(A) Immediately report directly to the commission any potential market manipulations, including market power abuse, and any discovered or potential violations of commission rules or ERCOT protocols or operating guides;

(B) Periodically report abnormal bids, offers, operational activities, and market behavior that have not been reported in accordance with paragraph (1) of this subsection or subsection (k) of this section.

(C) Regularly communicate with the commission and commission staff, and keep the commission updated regarding its activities, findings, and observations;

(D) Coordinate with the commission to identify priorities; and

(E) Coordinate with the commission to assess the resources and methods for monitoring the wholesale market effectively, including consulting needs.

(m) **ERCOT's responsibilities and support role.** ERCOT and the IMM shall jointly develop procedures and interfaces to ensure that the IMM director and staff have full access to ERCOT's operations centers, staff, and records relating to operations, settlement, and reliability. ERCOT shall designate liaisons to facilitate communications with the IMM on ERCOT's operations and information technology.

(1) ERCOT shall develop and operate an information system to collect and to store data required by the ERCOT protocols, and shall provide adequate communication equipment and necessary software packages to enable the IMM to establish electronic access to the information system and to facilitate the development and application of quantitative tools necessary for the market monitoring function. Data from ERCOT's source systems must be capable of being replicated in near real time and available for query by the IMM until data are archived and archived data are accessible for high-speed information searches. When an IT system failure prohibits "near real time" replication of data, ERCOT shall replicate the data as expeditiously as possible. Data archives must be designed to accommodate remote access by the IMM and the commission staff at any time.

(2) On an ongoing basis, ERCOT shall implement necessary procedures for the accurate collection and storage of data in the data archives and accurate communication of those data for use by the commission staff and the IMM.

(3) The IMM may review the catalogs describing information and data, and may review data collection verification criteria developed by ERCOT. The IMM may propose changes, additions, or deletions to the catalogs and criteria to facilitate the market monitoring function. In so doing, the IMM may require database items or evaluation criteria for inclusion in the pertinent catalogs.

(4) ERCOT shall establish procedures to ensure that the IMM may access all data maintained by ERCOT relating to operations, settlements, and reliability.

(5) ERCOT may provide administrative support and goods and services to the IMM, such as office space, payroll, and related services, and information technology support.

(n) **Liability of the IMM.** The IMM, and its directors, officers, employees and agents, shall not be liable to any person or entity for any act or omission, other than an act or omission constituting gross negligence or intentional misconduct, arising under or relating to this section, including but not limited to liability for any financial loss, loss of economic advantage, opportunity cost, or actual, direct, indirect or consequential damages of any kind resulting from or attributable to any such act or omission of the IMM as long as such act or omission arose from or related to matters within the scope of the IMM's authority.

(o) **Contractual Provisions.**

(1) Effective July 1, 2007, ERCOT shall include the following provision in any new or re-negotiated agreement it has with an entity that engages in any activity that is in whole or in part the subject of the ERCOT Protocols:

The IMM, and its directors, officers, employees, and agents, shall not be liable to any person or entity for any act or omission, other than an act or omission constituting gross negligence or intentional misconduct, including but not limited to liability for any financial loss, loss of economic advantage, opportunity cost, or actual, direct, indirect, or consequential damages of any kind resulting from or attributable to any such act or omission of the IMM, as long as such act or omission arose from or is related to matters within the scope of the IMM's authority arising under or relating to PURA §39.1515 and Public Utility Commission Substantive Rule §25.365, relating to Independent Market Monitor.

(2) Not later than 15 months after this subsection takes effect, ERCOT shall include the provision set out in paragraph (1) of this subsection in every agreement it has with an entity that engages in any activity that is in whole or in part the subject of the ERCOT Protocols.

§25.366. Internet Broadcasting of Public Meetings of an Independent Organization.

(a) **Purpose.** This section establishes the requirements for the Internet broadcasting of public meetings of an independent organization pursuant to Public Utility Regulatory Act (PURA) §39.1511(c).

(b) **Applicability.** This section applies to any organization that the commission has certified as an independent organization pursuant to PURA §39.151.

(c) **Internet Broadcasting.** An independent organization shall make publicly accessible without charge live Internet video of all public meetings for viewing from a link posted to the organization's Internet website. For purposes of this subsection, public meetings are meetings of the governing body of an independent organization, and meetings of any committee or subcommittee of the governing body of the independent organization but do not include meetings of the governing body of a regional reliability entity operating under the authority of the Energy Policy Act of 2005. A governing body or a committee or a subcommittee subject to this section may enter into executive session closed to the public and without live Internet video to address sensitive matters such as confidential information related to personnel matters, contracts, or lawsuits, competitively sensitive information, information related to the security of the regional electrical network, or other information that is required to be protected from release to the public.

(d) **Cost Recovery by the Independent Organization.** The independent organization may recover the costs of complying with this section through fees approved by the commission.

§25.381. Capacity Auctions.

(a) **Applicability.** This section applies to all affiliated power generation companies (PGCs) as defined in this section in Texas. This section does not apply to electric utilities subject to the Public Utility Regulatory Act (PURA) §39.102(c) until the end of the utility's rate freeze. It is recognized that certain commission orders issued during 2001 have effectively delayed competition in the service territories of Southwestern Electric Power Company (SWEPCO) and Entergy Gulf States, Inc. (EGSI). This section shall apply to auctions conducted after 2001 by SWEPCO and/or EGSI only when competition is implemented in their respective service territories.

(b) **Purpose.** The purpose of this section is to promote competitiveness in the wholesale market through increased availability of generation and increased liquidity by requiring electric utilities and their affiliated PGCs to sell at auction entitlements to at least 15% of the affiliated PGC's Texas jurisdictional installed generation capacity, describing the form of products required to be auctioned, prescribing the auction process, and prescribing a true-up procedure, in accordance with PURA §39.262(d)(2).

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

(1) **Affiliated power generation company (PGC)** — Any affiliated power generation company that is unbundled from the electric utility in accordance with PURA §39.051.

(2) **Assigned units** — The PGC-specific generating units that form the block of capacity from which an entitlement is sold.

(3) **Auction start date** — The date on which an auction begins.

(4) **Business day** — Any day on which the affiliated PGC's corporate offices are open for business and that is not a banking holiday.

(5) **Capacity auction product** — One of the following: "baseload", "gas-intermediate", "gas-cyclic", or "gas-peaking". Each capacity auction product is further described in subsections (f) and (g) of this section.

(6) **Close of business** — 5:00 p.m., central prevailing time.

(7) **Congestion zone** — An area of the transmission network that is bounded by commercially significant transmission constraints or otherwise identified as a zone that is subject to transmission constraints, as defined by an independent organization.

(8) **Credit rating** — A credit rating on an entity's senior unsecured debt, the entity's corporate credit rating, or the entity's issuer rating.

(9) **Daily gas price** — The index posting for the date of flow in the Financial Times energy publication "Gas Daily" under the heading "Daily Price Survey" for East-Houston-Katy, Houston Ship Channel. For EGSI gas entitlements in the eastern congestion zone, the daily gas price will utilize the "Gas Daily" index posting for Henry Hub. For EGSI gas entitlements in the western congestion zone, the daily gas price will be an average of the "Gas Daily" index posting for East-Houston-Katy, Houston Ship Channel.

(10) **Day-ahead** — The day preceding the operating day.

(11) **Entitlement or capacity entitlement** — The right to purchase and receive, under the applicable capacity auction master agreement, a block of 25 megawatts (MW) of electrical capacity and energy from the assigned units for a specific capacity auction product for one calendar month.

(12) **Forced outage** — An unplanned component failure or other condition that requires the unit be removed from service before the end of the next weekend.

(13) **Holder** — A person or entity that has acquired ownership of an entitlement under the terms of the applicable capacity auction Master Agreement.

(14) **Installed generation capacity** — All potentially marketable electric generation capacity owned by an affiliated PGC, including the capacity of:

(A) Generating facilities that are connected with a transmission or distribution system;

(B) Generating facilities used to generate electricity for consumption by the person owning or controlling the facility; and

(C) Generating facilities that will be connected with a transmission or distribution system and operating within 12 months.

(15) **Master Agreement or Agreement** — The applicable Capacity Auction EEI/NEMA Master Power Purchase & Sale Agreement.

(16) **Starts** — Direction by the holder of an entitlement to dispatch a previously idle entitlement.

(17) **Texas jurisdictional installed generation capacity** — The amount of an affiliated PGC's installed generation capacity properly allocable to the Texas jurisdiction. Such allocation shall be calculated pursuant to an existing commission-approved allocation study, or other such commission-approved methodology, and may be adjusted as approved by the commission to reflect the effects of divestiture or the installation of new generation facilities.

(d) **General requirements**. Subject to the qualifications for auction entitlements and the auction process described in subsections (e) and (h) of this section, each affiliated PGC subject to this section shall sell at auction capacity entitlements equal to at least 15% of the affiliated PGC's Texas jurisdictional installed generation capacity. Divestiture of a portion of an affiliated PGC's Texas jurisdictional installed generation capacity will be counted toward satisfaction of the affiliated PGC's capacity auction requirement only if the divestiture is made pursuant to a commission order in a business combination proceeding pursuant to PURA §14.101, and after the transfer of the assets and operations to a third party.

(e) **Product types and characteristics.**

(1) **Available entitlements and amounts**. The following products, defined separately in subsection (f) of this section for Electric Reliability Council of Texas, Inc. (ERCOT) and in subsection (g) of this section for non-ERCOT areas, shall be auctioned as capacity entitlements under subsection (d) of this section. Upon showing of good cause by the affiliated PGC and approval by the commission, an affiliated PGC may propose to auction entitlements different from those described in this section, including unit-specific capacity. Each affiliated PGC shall auction an amount of each applicable product in proportion to the amount of Texas jurisdictional installed generating capacity on the affiliated PGC's system that are the respective type of generating units. An affiliated PGC that owns generation in multiple congestion zones shall auction entitlements for delivery in each congestion zone. The amount of each product auctioned in each zone shall be in proportion to the amount of the respective type of generating units located in that zone, but the total shall not be less than 15% of the affiliated PGC's Texas jurisdictional installed generation capacity. The available entitlements for the months of March, April, May, October, and November of each year may be reduced in proportion to the average annual planned outage rate for the group of generating units associated with each type of entitlement. Entitlements shall be for system capacity.

(2) **Forced outages.** For any given congestion zone:

(A) For all entitlements except those described in subparagraph (B) of this paragraph, if all units providing capacity to an entitlement product experience a forced outage or an emergency condition prevents or restricts the ability of an affiliated PGC to dispatch a particular entitlement product, the entitlements of that product may be reduced in proportion to the percentage reduction in capacity of the units assigned to that entitlement; provided that such reductions in availability of any single entitlement do not exceed 2.0% of the total monthly energy available from the entitlement.

(B) For entitlements that are supported by two or fewer generating units, if one or more of the units providing capacity to an entitlement product experiences a forced outage or an emergency condition that prevents or restricts the ability of an affiliated PGC to dispatch a particular entitlement product, the entitlements of that product may be reduced in proportion to the percentage reduction in capacity of the units assigned to that entitlement; provided that such reductions in availability of any single entitlement do not exceed the most recent three-year rolling average of the forced outage rate for the unit(s) supporting the entitlement. The three-year rolling average of the forced outage rate applicable to entitlements under this subparagraph shall be included in the notice of capacity available for auction, under subsection (h)(2)(B)(ii)(II) of this section.

(C) Notification of any such reductions will take place as soon as possible, but in any event, at least one hour prior to the hour-ahead scheduling period applicable to when the reduction is to take place.

(3) **Planned outage.** The total MW reduction for planned outages is determined by calculating the average MW of monthly planned outage for the generating plants associated with a product over the previous three calendar years, multiplied by 12. The resulting planned outage hours are then rounded down to the nearest whole entitlement (25 MW block). These "outage entitlements" can then be removed from any of the five specified outage months (March, April, May, October, and November) in any combination.

(4) **Generation units offered**. If an affiliated PGC changes the assignment of a power generation unit to one of the four available product entitlements (baseload, gas-intermediate, gas-cyclic, or gas-peaking), then the affiliated PGC shall file with the commission the proposed changes in its assignment of each of its power generation units to one of the four available product entitlements and the resulting amount of each type of entitlement to be auctioned. As part of this filing, the affiliated PGC shall provide planned outage histories for the years 1998, 1999, and 2000 for each generating unit to be used to calculate the average annual planned outage rate for each group of generating units. Interested parties shall have 30 days in which to provide comments on the affiliated PGC's proposed changed assignments. If no comments are received, the affiliated PGC's proposed assignment shall be deemed appropriate. If any party objects to the affiliated PGC's proposed assignments, then the commission shall determine the appropriate assignment considering the manner in which the affiliated PGC expects to use such generation units.

(5) **Obligations of affiliated PGC**. The affiliated PGC shall dispatch entitlements only as directed by the holder of the entitlement in accordance with the applicable product description. The affiliated PGC may not refuse to dispatch the entitlement and may not curtail the dispatch of an entitlement unless expressly authorized by this section or by the applicable Master Agreement, or unless directed to do so by the independent organization in order to alleviate a system emergency. The affiliated PGC shall specify in its notice provided pursuant to subsection (h)(2)(B) of this section the point on the transmission system where energy from each entitlement is delivered to the entitlement holder.

(6) **Entitlement holder receives no possessory interest or obligations.**

(A) No possessory interest. The entitlements sold at auction shall include no possessory interest in the unit or units from which the power is produced.

(B) No possessory obligations. The entitlements sold at auction shall include no obligation of a possessory owner of an interest in the unit or units from which the power is produced.

(C) Scheduling. The entitlement holder shall have the right to designate the dispatch of the entitlement, subject to other provisions of this subsection and the scheduling limitations provided for in the applicable Agreement.

(7) **Credit requirements.**

(A) Standards. Entities submitting bids and all entitlement holders shall satisfy one of the following credit standards:

(i) The entity holds an investment grade credit rating (BBB- or Baa3 from Standard and Poor's or Moody's respectively or an equivalent);

(ii) The entity provides an escrowed deposit equal to the capacity price for the shorter of the duration of the entitlement or three months plus the amount that would be paid to exercise the entitlement for the shorter of the duration of the entitlement or three months at the assumed dispatch provided in either subsection (h)(6)(A)(iii) or subsection (h)(6)(C)(vi) of this section;

(iii) The entity provides a letter of credit or surety bond equal to the capacity price for the shorter of the duration of the entitlement or three months plus the amount that would be paid to exercise the entitlement for the shorter of the duration of the entitlement or three-months at the assumed dispatch provided in either subsection (h)(6)(A)(iii) or subsection (h)(6)(C)(vi) of this section, irrevocable for the duration of the entitlement;

(iv) The entity provides a guaranty from another entity with an investment grade credit rating; or

(v) The entity makes other suitable arrangements with the affiliated PGC, provided that the affiliated PGC makes such arrangements available on a non-discriminatory basis.

(B) Unsecured credit. To be eligible for unsecured credit, entities submitting bids shall satisfy the criteria in either clause (i), (ii), or (iii) of this subparagraph, with the amount of unsecured credit to be provided to such entities to be determined as follows:

(i) For bidders with an investment grade credit rating. The amount of credit available to a bidder relying on an investment grade credit rating of itself or its guarantor will be determined according to procedures set out below. If the bidding entity or its guarantor has an investment grade credit rating and minimum equity of $100 million, the amount of credit available will be determined using the lesser of $125 million, or the applicable percentage of the bidder's stockholder equity set out in the following table, except that the amount of credit will be reduced to the extent appropriate to take into account any outstanding commitments that a bidder has for existing capacity auction entitlements.

Credit Rating (if split ratings, use lower rating)		**% of stockholder equity**
S&P	Moody's	
AAA	Aaa2	3.00%
AAA-	Aaa3	3.00%
AA+	Aa1	2.95%
AA	Aa2	2.85%
AA-	Aa3	2.70%
A+	A1	2.55%
A	A2	2.35%
A-	A3	2.10%
BBB+	Baa1	1.80%
BBB	Baa2	1.40%
BBB-	Baa3	0.70%
Below BBB-	Below Baa3	Must use another form of security

(ii) If the bidder is a municipality or cooperative not publicly rated. If the bidder is a municipality or electric cooperative that is not publicly rated but has a minimum equity (patronage capital) of $25 million, a minimum times-interest-earned ratio (TIER) of 1.05, a minimum debt service coverage (DSC) ratio of 1.00, and a minimum equity-to-assets ratio of 0.15, then the amount of credit will be the lesser of $125 million or 5.0% of the bidder's unencumbered assets, except that the amount of credit will be reduced to the extent appropriate to take into account any outstanding commitments that a bidder has for existing capacity auction entitlements.

(iii) If the bidder is a privately-held entity not publicly rated. If the bidder is a privately-held entity that is not publicly rated, but has a minimum equity of $100 million, a minimum tangible net worth of $100 million, a minimum current ratio of 1.0, a maximum debt-to-capital ratio of 0.60, and a minimum ratio of earnings before interest, taxes, depreciation, and amortization (EBITDA) to interest and current maturities of long term debt (CMLTD) of 2.0, then the amount of credit will be the lesser of $125 million or 1.80% of the bidder's stockholder equity, except that the amount of credit will be reduced to the extent appropriate to take into account any outstanding commitments that a bidder has for existing capacity auction entitlements.

(C) All cash and other instruments used as credit security shall be unencumbered by pledges for collateral.

(D) If a bidder or entitlement holder chooses to use a surety bond to satisfy its credit requirements, then the form of such surety bond will be negotiated in good faith between the bidder or entitlement holder and the affiliated PGC and reasonably acceptable by an issuer of surety bonds.

(E) In the event the holder of the entitlement initially relied on its investment grade credit rating but subsequently loses it during the entitlement period, the holder of the entitlement shall provide alternative financial evidence within three business days.

(F) The holder of the entitlement shall notify the affiliated PGC of any material changes that impact its compliance with the financial requirements it relied on in meeting the credit standards in this section.

(G) In the event the holder or seller of the entitlement fails to meet or continue to meet its security requirement, or an Event of Default results in the termination of the Agreement, the entitlement shall revert to the affiliated PGC and shall be auctioned in the next auction for which notice can be provided of the sale of the entitlement pursuant to subsection (h)(2)(B) of this section.

(H) If an entitlement holder's creditworthiness or financial security materially and adversely changes after the auction is completed, as a result of an event specified in the Agreement, the affiliated PGC shall provide the entitlement holder with written notice requesting additional credit support or performance assurance in a commercially reasonable manner, as set forth in the Agreement. The seller's credit requirements shall clearly identify objective criteria that would trigger a request for additional security and the methods and time frame in which an entitlement holder must satisfy such a request. The affiliated PGC may suspend delivery of any capacity or energy for which the affiliated PGC has not already received payment until the performance assurance is received, in accordance with the Agreement.

(I) If at any time after the auction is completed, there shall occur a downgrade event with respect to the credit standing of the seller, then the entitlement holder may require the seller to provide a credit assurance in an amount determined by the entitlement holder in a commercially reasonable manner. In the event the seller fails to provide a commercially reasonable performance assurance or guarantee within three business days of the receipt of notice, then an event of default shall be deemed to have occurred, and the entitlement holder will be entitled to suspend performance under the Agreement and withhold payments for energy not yet delivered, and may ultimately terminate the Agreement after the suspension period as prescribed in the Agreement.

(f) **Product descriptions for capacity auctions in ERCOT**. The provisions in this subsection apply to capacity auctions in ERCOT. Subsection (g) of this section contains provisions applicable to capacity auctions in non-ERCOT areas.

(1) **Definitions.**

(A) The following words and terms, when used in this subsection shall have the following meanings, unless the context indicates otherwise.

(i) Balancing energy service down deployed — The number of megawatt-hours (MWh) of balancing energy service down deployed by ERCOT from an entitlement.

(ii) Balancing energy service up deployed — The number of MWh of balancing energy service up deployed by ERCOT from an entitlement.

(iii) Daily capacity commitment — The amount of capacity scheduled by an entitlement holder that an affiliated PGC must make available from an entitlement for the provision of energy or permitted ancillary services for an operating day from an entitlement.

(iv) Day-ahead schedule — A schedule submitted by an entitlement holder to an affiliated PGC of the entitlement holder's scheduled usage of the entitlement for the following operating day.

(v) Default qualifying scheduling entity (QSE) — The QSE that is designated by the entitlement holder to ERCOT as its default QSE.

(vi) Energy scheduled — The final schedule for energy, for each settlement interval, that an entitlement holder submits to an affiliated PGC, subject to the limits on timing and amounts of schedules contained in the capacity auction product descriptions.

(vii) Energy deployed down — The sum of regulation energy down energy deployed and balancing energy service down energy deployed.

(viii) Energy deployed up — The sum of regulation energy up energy deployed, responsive energy deployed, non-spinning energy deployed, and balancing energy service up energy deployed.

(ix) Grouped entitlements — All of the entitlements from an affiliated PGC that an entitlement holder holds for a particular entitlement month.

(x) Grouped ancillary services — The amount of each type of ancillary service available from each entitlement grouped by:

(I) Type of ancillary service;

(II) Type of capacity auction product; and

(III) Congestion zone for those ancillary services that are, or may be, dispatched by congestion zone.

(xi) Hour-ahead schedule — A schedule other than a day-ahead schedule submitted by an entitlement holder to an affiliated PGC no later than one hour before the end of an adjustment period of the entitlement holder's scheduled use of the entitlement for the operating hour corresponding to that adjustment period.

(xii) Non-spinning energy deployed — Energy deployed by ERCOT from the non-spinning reserve service as determined under the procedures in paragraph (2)(B) of this subsection.

(xiii) Product — Electric capacity, energy, capacity auction products or other product(s) related thereto as specified in a transaction by reference to a product listed in the Agreement or as otherwise specified by the parties in a transaction.

(xiv) Regulation energy down deployed — Energy deployed down by ERCOT from the regulation energy service as determined under the procedures of paragraph (2)(B) of this subsection.

(xv) Regulation energy up deployed — Energy deployed up by ERCOT from the regulation service as determined under the procedures of paragraph (2)(B) of this subsection.

(xvi) Responsive energy deployed — Energy deployed by ERCOT from the responsive reserve service as determined under the procedures of paragraph (2)(B) of this subsection.

(xvii) Two-day-ahead schedule — A schedule submitted by the entitlement holder to the affiliated PGC of the entitlement holder's scheduled usage of the entitlement for the operating day two days in the future.

(B) The following terms have the respective meanings given to them in the ERCOT protocols as amended from time to time:

(i) Ancillary services;
(ii) Balancing energy service;
(iii) Congestion zone;
(iv) Non-spinning reserve service;
(v) Operating day;
(vi) Operating hour;
(vii) Regulation service;
(viii) Responsive reserve service;
(ix) Settlement interval; and
(x) Zonal market clearing price.

(2) **General provisions.**

(A) Responsibility transfers.

(i) The entitlement holder may not use an entitlement for the provision of balancing energy service until a responsibility transfer (RT) between the entitlement holder's QSE and the affiliated PGC's QSE is established and operated in accordance with the ERCOT protocols for the deployment of balancing energy service. The entitlement holder shall establish a separate RT with the affiliated PGC for each congestion zone from which the entitlement holder desires to provide balancing energy service.

(ii) When ERCOT has developed the details and specifications of RTs between QSEs, including without limitation, mechanics, settlement, and communication, then, at the request of the entitlement holder, the parties shall negotiate in good faith to transfer responsibility between their respective QSEs to:

(I) Allow the entitlement holder to provide balancing energy service from the entitlement; and

(II) Allocate the cost of establishing that capability.

(iii) The entitlement holder's QSE shall act as the controller of RTs used for balancing energy service from an entitlement. The entitlement holder's QSE shall use RTs to provide instructions regarding balancing energy service to the affiliated PGC's QSE. These instructions shall comply with all the limitations in the applicable capacity auction product description.

(iv) Both the entitlement holder's QSE and the affiliated PGC's QSE shall enter an inter-QSE trade in accordance with the ERCOT protocols to represent an RT before any operating hour in which the entitlement holder deploys balancing energy service from an entitlement.

(v) The affiliated PGC's QSE is only responsible for complying with RTs sent by the entitlement holder's QSE and is not responsible for ERCOT instructions sent to the entitlement holder.

(vi) The affiliated PGC and the entitlement holder shall rely upon any integration of the RT over each settlement interval performed by ERCOT. If ERCOT does not perform that integration, then the integration shall be performed in a manner mutually agreed to by both parties.

(vii) The entitlement holder is deemed not to have provided any balancing energy service from an entitlement if the affiliated PGC loses or does not receive the balancing energy service signal from ERCOT. The affiliated PGC will promptly notify the entitlement holder if it does not receive or loses the balancing energy service signal from ERCOT.

(B) Deployment of energy from ancillary services. Subject to the limitations and conditions set out in this subsection, and except when the affiliated PGC is excused from hierarchical dispatch by ERCOT of ancillary services under clause (i) or (v) of this subparagraph, ERCOT shall be deemed to have dispatched ancillary services from the entitlements in the entitlement group in a hierarchical order according to the requirements of this subsection. Otherwise, ancillary services shall be dispatched for each entitlement in an entitlement group independently.

(i) Notice of grouped entitlements. Not later than five days before the beginning of an entitlement month, the entitlement holder shall notify the affiliated PGC of all entitlements from the affiliated PGC that are held by the entitlement holder for that entitlement month. The list shall contain sufficient detail for the affiliated PGC to identify the entitlements held by the entitlement holder for that month, including without limitation any unique entitlement number assigned by the affiliated PGC to the entitlement and listed on the letter confirmation for the entitlement. If the affiliated PGC does not timely receive this notice, then the affiliated PGC is excused from its obligation to dispatch ancillary services on a hierarchical basis under this section.

(ii) Amount of ancillary services scheduled from entitlements.

(I) The affiliated PGC shall track the amount of each ancillary service for each operating hour and the amount of each ancillary service scheduled by the entitlement holder for each operating hour, both for individual entitlements and for each grouped entitlement.

(II) For ancillary services other than the balancing energy service, which is determined by an RT, the amount of ancillary service scheduled from each entitlement and for each grouped entitlement for an operating hour is the amount stated in the final timely schedule submitted by the entitlement holder to the affiliated PGC for that operating hour for each entitlement or the entitlement group.

(iii) Deployed ancillary services.

(I) For balancing energy service, the amount of energy that ERCOT is deemed to have deployed is determined by the integration described in subparagraph (A) of this paragraph.

(II) For all ancillary services other than balancing energy service, the affiliated PGC shall track the deployment of ancillary services from the entitlement group by each grouped ancillary service for each hour in the entitlement month, except for hours in which the affiliated PGC is excused from dispatching ancillary services on a hierarchical basis under clause (i) or (v) of this subparagraph. The total amount of each grouped ancillary service deployed in an hour shall be calculated by the product of:

(-a-) The ratio of the amount of the grouped ancillary service scheduled by the entitlement holder from its grouped entitlements to the total amount of that specific ancillary service scheduled from resources in the affiliated PGC's QSE;

(-b-) The amount of energy deployed out of that grouped ancillary service in a particular congestion zone or in ERCOT as a whole, whichever is applicable.

(III) For all ancillary services other than balancing energy service, the amount of each ancillary service that ERCOT is deemed to have deployed from each entitlement, for hours in which the affiliated PGC is excused from dispatching ancillary services on a hierarchical basis under clause (i) or (v) of this subparagraph, shall be calculated by the product of:

(-a-) The ratio of the amount of that ancillary service scheduled by the entitlement holder from the entitlement to the total amount of that specific ancillary service scheduled from resources in the affiliated PGC's QSE;

(-b-) The amount of energy deployed by ERCOT out of that ancillary service in a particular congestion zone or in ERCOT as a whole, whichever is applicable.

(iv) Hierarchical deployment of grouped ancillary services.

(I) For determination of the contract price for each entitlement in a grouped entitlement, ERCOT is deemed to have first deployed grouped ancillary services that are deployed by congestion zone pursuant to subclause (III) of this clause with the amount for each entitlement spread proportionally among the entitlement holder's entitlements of that type in that congestion zone.

(II) After deploying grouped ancillary services by congestion zone pursuant to subclause (I) of this clause, ERCOT is deemed to have deployed the remainder of each grouped ancillary service pursuant to subclause (III) of this clause, with the amount for each type of entitlement spread proportionally among the entitlement holder's entitlements of that type in ERCOT.

(III) Deployed energy shall be assigned to the entitlement holder's entitlements that scheduled those ancillary services on a hierarchical basis as follows:

(-a-) For incremental deployments:

(-1-) First: Baseload entitlements, with the highest priority given to the Baseload entitlements with the lowest energy price;

(-2-) Second: Gas-intermediate entitlements;

(-3-) Third: Gas-cyclic entitlements; and

(-4-) Fourth: Gas-peaking entitlements.

(-b-) For decremental deployments:

(-1-) First: Gas-peaking entitlements;

(-2-) Second: Gas-cyclic entitlements;

(-3-) Third: Gas-intermediate entitlements; and

(-4-) Fourth: Baseload entitlements, with the highest priority given to the Baseload entitlements with the highest energy price.

(v) Exception to dispatching on hierarchical basis. The affiliated PGC is not required to dispatch ancillary services from the entitlement group on a hierarchical basis if the affiliated PGC does not have the information necessary to dispatch ancillary services from the entitlement group in a hierarchical fashion. Necessary information includes, but is not limited to, the signal from

ERCOT deploying balancing energy service or the signal from ERCOT deploying other ancillary services.

(3) **Baseload product.**

(A) Baseload scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement. The entitlement holder shall submit a two-day-ahead schedule for the entitlement if notified to do so by ERCOT.

(ii) Timing of scheduling. All of the times for scheduling referred to in this subparagraph are based on the times in the ERCOT protocols. If the times in the ERCOT protocols are changed, then the times in this subparagraph will be considered to have changed to equitably accommodate the changes in the ERCOT protocols.

(I) The entitlement holder shall submit day-ahead or two-day-ahead schedules for the entitlement to the affiliated PGC no later than 8:00 a.m. The entitlement holder shall submit hour-ahead schedules for ancillary services from the entitlement to the affiliated PGC no later than one hour before the deadline for the affiliated PGC's QSE to submit hour-ahead schedules to ERCOT.

(II) On days that ERCOT allows QSEs to change their day-ahead or two-day-ahead schedules to ERCOT by 1:00 p.m. for congestion or capacity insufficiency, the entitlement holder may submit a revised day-ahead or two-day-ahead schedule for energy from the entitlement to the affiliated PGC no later than noon.

(III) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for the non-spinning reserve ancillary services from the entitlement no later than 1:45 p.m. The entitlement holder cannot change the amount of energy scheduled in a revised schedule for the non-spinning reserve ancillary services.

(IV) No hour-ahead schedules are permitted for energy from baseload entitlements. Hour-ahead schedules are permitted for ancillary services from baseload entitlements.

(iii) Schedule content. Each schedule shall specify, for each settlement interval, the MW of energy scheduled to be delivered to the entitlement holder from the entitlement and the MW of each permitted ancillary service to be scheduled from the entitlement, subject to the scheduling limits in clause (iv) of this subparagraph.

(iv) Scheduling limits.

(I) Minimum energy. The entitlement holder may not schedule energy at less than 20 MW from the entitlement at any time during the month.

(II) Ancillary services. The entitlement holder may use a baseload entitlement to provide responsive reserve service at a level of one MW, and non-spinning reserve service, up to a combined total of three MW. The baseload entitlement may not be used for any other ancillary service. Non-spinning reserve service may be provided from the entitlement in 30 minutes, and responsive reserve service may be provided from the entitlement in ten minutes.

(III) Maximum changes. Subject to the minimum energy rate specified in subclause (I) of this clause, the rate at which the entitlement holder schedules energy in each hour generally cannot change more than plus or minus two MW. The following additional restrictions apply.

(-a-) If the entitlement holder schedules or reserves any ancillary services in an hour, then the level of energy scheduled shall be the same in each settlement interval of the hour.

(-b-) The maximum change in ancillary services scheduled from the first settlement interval in one hour to the first settlement interval of the next hour is plus or minus three MW.

(-c-) The maximum change in energy scheduled from the first settlement interval in one hour to the first settlement interval in the next hour is plus or minus two MW.

(-d-) The maximum change in energy scheduled from one settlement interval to the next is plus or minus one MW.

(IV) Starts. The entitlement holder shall schedule energy from a baseload entitlement for every settlement interval and may not direct any starts of the entitlement.

(V) Default schedule. If the entitlement holder does not submit a timely day-ahead or two-day ahead schedule, as applicable, then the schedule for the applicable operating day is deemed to be 20 MW of energy and zero MW of ancillary services to be delivered to the entitlement holder's designated default QSE in every settlement interval of the applicable operating day.

(B) Contract price for baseload. The items included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment. The fuel cost owed to the affiliated PGC by the entitlement holder for the dispatched baseload power will be the average cost of coal, lignite, and nuclear fuel (in dollars per MWh), as applicable to the appropriate congestion zone in which the underlying generation units are located, based on the affiliated PGC's final excess cost over market (ECOM) model as determined pursuant to PURA §39.201. Affiliated PGCs of the electric utilities without an ECOM determination in their proceeding conducted pursuant to PURA §39.201 shall propose, for commission review, an average cost of fuel in a similar manner. The energy payment from the entitlement holder to the affiliated PGC is the fuel cost in dollars per MWh for the entitlement times the greater of:

(I) The sum of the total energy scheduled from the entitlement during the entitlement month plus energy deployed up from the entitlement during the entitlement month; or

(II) An amount of MWh equal to 20 MW times the number of hours in the entitlement month.

(iii) Ancillary services payment. For baseload entitlements, the ancillary services payment to be paid by the entitlement holder to the affiliated PGC is zero.

(iv) Energy deployed up reimbursement payment. For energy deployed up, for all settlement intervals in the entitlement month, the affiliated PGC shall pay the entitlement holder the sum of the zonal market clearing price of energy (MCPE) in dollars per MWh paid by ERCOT for that settlement interval times the energy deployed up in that settlement interval.

(v) Energy deployed down reimbursement payment. For energy deployed down for all settlement intervals in the entitlement month, the entitlement holder shall pay the affiliated PGC the sum of the MCPE in dollars per MWh paid to ERCOT for that settlement interval times the energy deployed down in that settlement interval.

(C) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price to the affiliated PGC after receiving an invoice for that amount in accordance with the other terms of the applicable Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the other terms of the Agreement.

(4) **Gas-intermediate product.**

(A) Gas-intermediate scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement and may submit hour-ahead schedules. The entitlement holder shall submit a two-day-ahead schedule for the entitlement if notified to do so by ERCOT.

(ii) Timing of scheduling. All of the times for scheduling referred to in this subparagraph are based on the times in the ERCOT protocols. If the times in the ERCOT protocols are changed, then the times in this subparagraph will be considered to have changed to equitably accommodate the changes in the ERCOT protocols.

(I) The entitlement holder shall submit day-ahead or two-day-ahead schedules for the entitlement to the affiliated PGC no later than 8:00 a.m. The daily capacity commitment is determined for a gas-intermediate entitlement by the 8:00 a.m. schedule. The entitlement holder shall submit hour-ahead schedules for ancillary services for the entitlement to the affiliated PGC no later than one hour before the deadline for the affiliated PGC's QSE to submit hour-ahead schedules to ERCOT.

(II) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for energy from the entitlement no later than 10:00 a.m., subject to the limit on maximum energy in clause (iv)(I)(-b-) of this subparagraph.

(III) On days that ERCOT allows QSEs to change their day-ahead or two-day-ahead schedules to ERCOT by 1:00 p.m. for congestion or capacity insufficiency, the entitlement holder may submit a revised day-ahead or two-day-ahead schedule for energy from the entitlement to the affiliated PGC no later than noon, subject to the limit on maximum energy in clause (iv)(I)(-b-) of this subparagraph.

(IV) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for ancillary services from the entitlement no later than 1:45 p.m. The entitlement holder cannot change the amount of energy scheduled in a revised schedule for ancillary services.

(V) No hour-ahead schedules are permitted for energy from gas-intermediate entitlements. Hour-ahead schedules are permitted for ancillary services from gas-intermediate entitlements.

(iii) Schedule content. Each schedule shall specify:

(I) For each settlement interval, the MW of energy scheduled to be delivered to the entitlement holder from the entitlement; and

(II) For each hour, the MW scheduled to be reserved for the entitlement holder's use of each ancillary service from the entitlement. The entitlement holder shall include any MW bid (but not pricing) for the balancing energy up and balancing energy down ancillary services on the schedule.

(iv) Scheduling limits.

(I) Total. Generally, the rate at which energy is scheduled cannot change more than plus or minus six MW and the rate at which ancillary services is reserved or scheduled by the entitlement holder in each hour cannot change more than plus or minus six MW. The restrictions in items (-a-) and (-b-) of this subclause apply.

(-a-) Minimum energy. The entitlement holder may not schedule energy at less than eight MW from the entitlement at any time during the month, unless the entitlement holder has elected the gas-intermediate Start Option, in which case the entitlement holder may reduce energy below eight MW as specified in subclause (IV)(-a-) of this clause.

(-b-) Maximum energy. The entitlement holder may not schedule energy at any level greater than the daily capacity commitment in any settlement interval.

(II) Maximum changes. Subject to the limitations specified in subclause (I) of this clause:

(-a-) Generally, the rate at which energy is scheduled by the entitlement holder in each hour cannot change more than plus or minus six MW and the rate at which ancillary services are scheduled or reserved by the entitlement holder in each hour cannot change more than plus or minus six MW. The restrictions in items (-b-) and (-c-) apply.

(-b-) Energy. Subject to the maximum change specified in item (-a-) of this subclause:

(-1-) The maximum change in energy scheduled from the first settlement interval in one hour to the first settlement interval of the next hour is plus or minus six MW.

(-2-) Subject to the limitation in subitem (-1-) of this item, the maximum change in energy scheduled from one settlement interval to the next is plus or minus two MW.

(-c-) Ancillary services. Subject to the maximum change specified in item (-a-) of this subclause, the maximum change in ancillary services scheduled from the first settlement interval in one hour to the first settlement interval of the next hour is plus or minus six MW.

(III) Ancillary services. Subject to the limitations in subclauses (I) and (II) of this clause:

(-a-) The total MW of non-spinning reserve service, regulation service up, regulation service down, responsive reserve service, and balancing energy service up and balancing energy service down from the entitlement in one hour shall not exceed ten MW;

(-b-) Subject to the limitations in item (-a-) of this subclause, the total MW of regulation service up, regulation service down, responsive reserve service, and bids for balancing energy service up and balancing energy service down from the entitlement in one hour shall not exceed:

(-1-) Four MW if the entitlement holder schedules any two-MW changes in the levels of energy within the hour;

(-2-) Five MW if the entitlement holder schedules any one-MW, but not two-MW changes in the levels of energy within the hour; or

(-3-) Six MW if the entitlement holder does not schedule any changes in the levels of energy within the hour.

(-c-) In addition to the limitations in items (-a-) and (-b-) of this subclause, the total MW of non-spinning reserve service, regulation service up, responsive reserve service, and balancing energy service up from the entitlement in a settlement interval shall not exceed an amount of MW equal to the daily capacity commitment for the settlement interval minus the energy scheduled for that settlement interval.

(-d-) In addition to the limitations in items (-a-), (-b-), and (-c-) of this subclause, the total MW of regulation service down and balancing energy service down from the entitlement in a settlement interval shall not exceed an amount of MW equal to the energy scheduled for that settlement interval minus eight MW.

(-e-) In addition to the limitations in items (-a-), (-b-), and (-c-) of this subclause, if the energy schedule is at zero as permitted under subclause (IV)(-a-) of this clause, then the entitlement holder may not schedule any ancillary services from the gas-intermediate entitlement.

(-f-) Non-spinning reserve service may be provided from the entitlement in 30 minutes, and other permitted ancillary services may be provided from the entitlement in ten minutes.

(IV) Starts, minimum off time, and minimum run time.

(-a-) The entitlement holder may reduce the energy schedule from the gas-intermediate entitlement to zero MW two times during the entitlement month.

(-b-) Once the energy schedule is reduced to zero, it shall remain at zero for not less than 48 hours.

(-c-) If the entitlement holder increases the energy schedule from zero, then energy shall be scheduled at a minimum of eight MW, and the energy schedule may not be reduced to zero again for at least 72 hours after the energy schedule increased from zero.

(v) Default schedule. If the entitlement holder does not submit a timely day-ahead or two-day ahead schedule, as applicable, then the schedule, for the applicable operating day is deemed to be, in every settlement interval of the applicable operating day, eight MW for the daily capacity commitment, eight MW of energy to be delivered to the entitlement holder's designated default QSE, and zero MW of ancillary services, and that deemed schedule may not be changed in any hour-ahead schedule. However, if the entitlement holder has used up its allowable starts for the entitlement month, then the schedule for the applicable operating day is deemed to be, in every settlement interval of the applicable operating day, zero MW for the daily capacity commitment.

(B) Gas-intermediate ancillary services. Subject to the scheduling limits in subparagraph (A) of this paragraph, the entitlement holder may use the entitlement in any one hour for one or more of these ancillary services: regulation service up, regulation service down, responsive reserve service, non-spinning reserve service, balancing energy service up, and balancing energy service down. When ERCOT requires mandatory balancing energy down bids, then the affiliated PGC shall so notify the entitlement holder, and the entitlement holder shall then submit a balancing energy down bid to ERCOT in the same percentage that ERCOT requires of the affiliated PGC, subject to the MW limits for gas-intermediate in the applicable Schedule CA of the applicable Agreement.

(C) Contract price for gas-intermediate. The items included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment from the entitlement holder to the affiliated PGC for each settlement interval in the entitlement month, is the sum of the minimum energy payment and the excess energy payment.

(-a-) The minimum energy payment is the product of the number of hours in the entitlement month at which the energy level is not zero as permitted under subparagraph (A)(iv)(IV)(-a-) of this paragraph, times eight MWh, times the minimum fuel price.

(-b-) The excess energy payment for each settlement interval is the excess fuel price defined in subclause (II)(-b-) of this clause, times (energy scheduled minus two MWh plus energy deployed up minus energy deployed down).

(II) Fuel price.

(-a-) The minimum fuel price is a heat rate equal to 9.9 Million British Thermal Units (MMBtu) per MWh times the daily gas price.

(-b-) The excess fuel price is a heat rate equal to 9.9 MMBtu per MWh times the daily gas price.

(iii) Ancillary services payment.

(I) The ancillary services cost adjustment payment to be paid by the entitlement holder to the affiliated PGC is the ancillary services cost defined in subclause (II) of this clause times the difference, for each settlement interval of the entitlement, between the daily capacity commitment and energy scheduled.

(II) The ancillary services cost is a heat rate adjustment equal to 1.015 MMBtu per MW times the daily gas price.

(iv) Energy deployed up reimbursement payment. For energy deployed up for all settlement intervals in the entitlement month, the affiliated PGC shall pay the entitlement holder the MCPE in dollars per MWh paid by ERCOT for a settlement interval times the energy deployed up in a settlement interval.

(v) Energy deployed down reimbursement payment. For energy deployed down for all settlement intervals in the entitlement month, the entitlement holder shall pay the affiliated PGC the MCPE in dollars per MWh paid to ERCOT for a settlement interval times the energy deployed down in a settlement interval.

(D) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the Agreement.

(5) **Gas-cyclic.**

(A) Gas-cyclic scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement and may submit hour-ahead schedules for both energy and ancillary services. The entitlement holder shall submit a two-day-ahead schedule for the entitlement if notified to do so by ERCOT.

(ii) Timing of scheduling. All of the times for scheduling referred to in this subparagraph are based on the times in the ERCOT protocols. If the times in the ERCOT protocols are changed, then the times in this subparagraph will be considered to have changed to equitably accommodate the changes in the ERCOT protocols.

(I) The entitlement holder shall submit day-ahead or two-day-ahead schedules for the entitlement to the affiliated PGC no later than 8:00 a.m. The daily capacity commitment is determined for a gas-cyclic entitlement by the 8:00 a.m. schedule, unless the entitlement holder notifies the affiliated PGC, in the schedule, that it is exercising its option to set the daily capacity commitment in the last schedule submitted before the gas-cyclic start deadline defined in subclause (V) of this clause. The entitlement holder shall submit hour-ahead schedules for the entitlement to the affiliated PGC no later than one hour before the deadline for the affiliated PGC's QSE to submit hour-ahead schedules to ERCOT.

(II) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for energy from the entitlement no later than 10:00 a.m.

(III) On days that ERCOT allows QSEs to change their day-ahead or two-day ahead schedules to ERCOT by 1:00 p.m. for congestion or capacity insufficiency, the entitlement holder may submit a revised day-ahead or two-day-ahead schedule for energy from the entitlement to the affiliated PGC no later than noon.

(IV) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for ancillary services from the entitlement no later than 1:45 p.m.

(V) The gas-cyclic start deadline for declaring the daily capacity commitment for each settlement interval in an operating hour is 14 hours before the end of the adjustment period for that operating hour.

(iii) Schedule content. Each schedule shall specify:

(I) For each settlement interval, the MW of energy scheduled to be delivered to the entitlement holder from the entitlement; and

(II) For each hour, the MW scheduled to be reserved for the entitlement holder's use of each ancillary service from the entitlement. The entitlement holder shall include any MW bid (but not pricing) for the balancing energy up and balancing energy down ancillary services on the schedule.

(iv) Scheduling limits.

(I) Total. Generally, the rate at which energy is scheduled cannot change more than plus or minus six MW and the rate at which ancillary services is reserved or scheduled by the entitlement holder in each hour cannot change more than plus or minus six MW. The restrictions in items (-a-) and (-b-) of this subclause apply.

(-a-) Minimum energy. The entitlement holder may not schedule energy at any level between zero MW and five MW from the entitlement at any time during the month.

(-b-) Maximum energy. The entitlement holder may not schedule energy at any level greater than the daily capacity commitment in any settlement interval after the entitlement holder designates its daily capacity commitment.

(II) Maximum changes. Subject to the limits specified in subclause (I) of this clause:

(-a-) The maximum change in the rate at which energy is scheduled from the first settlement interval in one hour to the first settlement interval in the next hour is plus or minus six MW;

(-b-) Subject to the limitation in item (-a-) of this subclause, the maximum change in the rate at which energy is scheduled from one settlement interval to the next is plus or minus two MW; and

(-c-) Subject to the limitation specified in item (-a-) of this subclause, the maximum change in ancillary services scheduled from the first settlement interval in one hour to the first settlement interval of the next hour is plus or minus six MW.

(III) Ancillary services. Subject to the limitations in subclauses (I) and (II) of this clause:

(-a-) The total MW of non-spinning reserve service, regulation service up, regulation service down, responsive reserve service, and balancing energy service up and balancing energy service down from the entitlement in one hour shall not exceed ten MW;

(-b-) Subject to the limitations in item (-a-) of this subclause, the total MW of regulation service up, regulation service down, responsive reserve service, and bids for balancing energy service up and balancing energy service down from the entitlement in one hour shall not exceed:

(-1-) Four MW if the entitlement holder schedules any two-MW changes in the levels of energy within the hour;

(-2-) Five MW if the entitlement holder schedules any one-MW, but not two-MW changes in the levels of energy within the hour; or

(-3-) Six MW if the entitlement holder does not schedule any changes in the levels of energy within the hour.

(-c-) In addition to the limitations in items (-a-) and (-b-) of this subclause, the total MW of non-spinning reserve service, regulation service up, responsive reserve service, and balancing energy service up from the entitlement in a settlement interval shall not exceed an amount of MW equal to the daily capacity commitment for the settlement interval minus the energy scheduled for that settlement interval.

(-d-) In addition to the limitations in items (-a-), (-b-), and (-c-) of this subclause, the total MW of regulation service down and balancing energy service down from the entitlement in a settlement interval shall not exceed an amount of MW equal to the energy scheduled for that settlement interval minus five MW.

(-e-) Non-spinning reserve service may be provided from the entitlement in 30 minutes, and other permitted ancillary services may be provided from the entitlement in ten minutes.

(IV) Starts. Subject to the limits specified in subclause (I) - (III) of this clause, the entitlement holder may not direct more than 20 starts during the month of the entitlement, and the entitlement holder may not direct more than one start per day. A start occurs every time a schedule increases the MW of energy from zero MW. Once 20 starts have occurred during the entitlement, the energy scheduled by the entitlement holder may not be lower than a rate of five MW unless that level is lowered to zero MW, at which time the level may not be raised above zero MW for the remainder of the entitlement.

(v) Default schedule. If the entitlement holder does not submit a timely day-ahead or two-day ahead schedule, as applicable, then the schedule for the applicable operating day is deemed to be, in every settlement interval of the applicable operating day, zero MW for the daily capacity commitment, zero MW of energy, and zero MW of ancillary services. This deemed schedule may not be changed in any hour-ahead schedule.

(B) Gas-cyclic ancillary services. Subject to the scheduling limits in subparagraph (A) of this paragraph, the entitlement holder may use the entitlement in any one hour for one or more of these ancillary services: regulation service up, regulation service down, responsive reserve service, non-spinning reserve service, balancing energy service up, and balancing energy service down. When ERCOT requires mandatory balancing energy service down bids, then the affiliated PGC shall so notify the entitlement holder, and the entitlement holder shall then submit a balancing energy service down bid in the same percentage that ERCOT requires of the affiliated PGC, subject to the MW limits for gas-cyclic in this paragraph.

(C) Contract price for gas-cyclic. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment for each settlement interval from the entitlement holder to the affiliated PGC is the fuel price defined in subclause (II) of this clause times (energy scheduled plus energy deployed up minus energy deployed down.)

(II) Fuel price.

(-a-) The fuel price, for the portion of the daily capacity commitment that is designated by the entitlement holder by 8:00 a.m. in the day-ahead or two-day-ahead schedule, is a heat rate equal to 12.100 MMBtu per MWh times the daily gas price.

(-b-) The fuel price, for the portion of the daily capacity commitment that is not released or committed at 8:00 a.m., but is committed before the gas-cyclic start deadline, is a heat rate equal to 12.100 MMBtu per MWh times (the sum of the daily gas price plus $ .25.)

(iii) Ancillary services payment.

(I) The ancillary services payment to be paid by the entitlement holder to the affiliated PGC is the product of the ancillary services cost defined in subclause (II) of this clause times the difference, for each settlement interval of the entitlement, between the daily capacity commitment and energy scheduled.

(II) The ancillary services cost is a heat rate adjustment equal to 1.622 MMBtu per MW times the daily gas price.

(iv) Energy deployed up reimbursement payment. For energy deployed up, for all settlement intervals in the entitlement month, the affiliated PGC shall pay the entitlement holder the MCPE in dollars per MWh paid by ERCOT for a settlement interval times the energy deployed up in a settlement interval.

(v) Energy deployed down reimbursement payment. For energy deployed down for all settlement intervals in the entitlement month, the entitlement holder shall pay the affiliated PGC the MCPE in dollars per MWh paid to ERCOT for a settlement interval times the energy deployed down in a settlement interval.

(D) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the other terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the other terms of the Agreement.

(6) **Gas-peaking.**

(A) Gas-peaking scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement and may submit hour-ahead schedules. The entitlement holder shall submit a two-day-ahead schedule for the entitlement if notified to do so by ERCOT.

(ii) Timing of scheduling. All of the times for scheduling referred to in this subparagraph are based on the times in the ERCOT protocols. If the times in the ERCOT protocols are changed, then the times in this subparagraph will be considered to have changed to equitably accommodate the changes in the ERCOT protocols.

(I) The entitlement holder shall submit day-ahead or two-day-ahead schedules for the entitlement to the affiliated PGC no later than 8:00 a.m. The daily capacity commitment is determined for a gas-peaking entitlement by the 8:00 a.m. schedule, unless the entitlement holder notifies the affiliated PGC, in the schedule, that it is exercising its option to set the daily capacity commitment in the last schedule submitted before the gas-peaking start deadline defined in subclause (V) of this clause. The entitlement holder shall submit hour-ahead schedules for the entitlement to the affiliated PGC no later than one hour before the deadline for the affiliated PGC's QSE to submit hour-ahead schedules to ERCOT.

(II) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for energy from the entitlement no later than 10:00 a.m.

(III) On days that ERCOT allows QSEs to change their day-ahead or two-day ahead schedules to ERCOT by 1:00 p.m. for congestion or capacity insufficiency, the entitlement holder may submit a revised day-ahead or two-day-ahead schedule for energy from the entitlement to the affiliated PGC no later than noon.

(IV) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for the non-spinning reserve service from the entitlement no later than 1:45 p.m.

(V) The gas-peaking start deadline for declaring the daily capacity commitment for each settlement interval in an operating hour is one hour before the end of the adjustment period for that operating hour.

(iii) Schedule content. Each schedule shall specify:

(I) For each settlement interval, the MW of energy scheduled to be delivered to the entitlement holder from the entitlement; and

(II) For each hour, the MW scheduled to be reserved for the entitlement holder's use of the non-spinning reserve service from the entitlement.

(iv) Scheduling limits.

(I) Total.

(-a-) The rate at which energy is scheduled or ancillary services reserved or scheduled by the entitlement holder in each settlement interval during an hour shall be either zero MW or 25 MW and cannot change during the hour.

(-b-) Subject to the requirement of item (-a-) of this subclause, if the entitlement holder schedules any energy from the entitlement in an hour, the rate at which energy is scheduled shall continue uninterrupted at a level of 25 MW for not less than four hours.

(-c-) Subject to the requirements of items (-a-) and (-b-) of this subclause, when the entitlement holder decreases a schedule for energy to zero MW from the entitlement in an hour, the rate at which energy is scheduled or at which ancillary services is scheduled or reserved shall continue uninterrupted at a level of zero MW for not less than two hours.

(II) Starts. The number of starts of the entitlement is not limited.

(v) Default schedule. If the entitlement holder does not submit a timely day-ahead or two-day ahead schedule, as applicable, then the schedule, for the applicable operating day is deemed to be, in every settlement interval of the applicable operating day, zero MW for the daily capacity commitment, zero MW of energy, and zero MW of the non-spinning reserve service. This deemed schedule may not be changed in any revised day-ahead or two-day ahead schedule, or in any hour-ahead schedule.

(B) Gas-peaking ancillary services. The entitlement holder may not use the entitlement for any ancillary service except the non-spinning reserve service.

(C) Contract price for gas-peaking. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment for each settlement interval, from the entitlement holder to the affiliated PGC is the fuel price defined in subclause (II) of this clause times (energy scheduled plus non-spinning energy deployed plus non-spinning energy instructed deviation.)

(II) Fuel price.

(-a-) The fuel price, for operating days for which the entitlement holder designated its daily capacity commitment by 8:00 a.m. in the day-ahead or two-day ahead schedule, is a heat rate equal to 14.100 MMBtu per MWh times the daily gas price.

(-b-) The fuel price, for operating days for which the entitlement holder exercises its option to designate its daily capacity commitment after 8:00 a.m. and before the gas-peaking start deadline, is a heat rate equal to 14.100 MMBtu per MWh times the sum of the daily gas price plus $ .25.

(iii) Ancillary services payment. The ancillary services payment to be paid by the entitlement holder to the affiliated PGC is the product of $1.00 per MW times the total number of MW of non-spinning reserve service scheduled during each hour of the entitlement month.

(iv) Ancillary services reimbursement payment. The ancillary services reimbursement payment from the affiliated PGC to the entitlement holder is the sum of the MCPE for energy in dollars per MWh paid by ERCOT for each MWh of non-spinning energy deployed and the price that ERCOT pays for uninstructed deviations for each MWh of non-spinning energy uninstructed deviation.

(D) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the other terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the other terms of the Agreement.

(g) **Product descriptions for capacity in non-ERCOT areas**. The provisions in this subsection apply to capacity auctions in non-ERCOT areas. Subsection (f) of this section contains provisions applicable to capacity auctions in ERCOT.

(1) **Definitions.** The following words and terms when used in this subsection shall have the following meanings unless the context indicates otherwise:

(A) Daily capacity commitment — The amount of capacity scheduled by the entitlement holder that a seller shall make available for the provision of energy from an entitlement.

(B) Day ahead schedule — A schedule submitted by the entitlement holder to a seller of the entitlement holder's scheduled usage of the entitlement for the following operating day.

(C) Energy scheduled — For each settlement interval, the final schedule for energy that the entitlement holder submits to a seller, subject to the limits on timing and amounts of schedules contained in this subsection.

(D) Grouped entitlements — All of the entitlements from a seller that the entitlement holder holds for a particular entitlement month.

(E) Hour-ahead schedule — A schedule other than a day-ahead schedule submitted by the entitlement holder to a seller of the entitlement holder's scheduled usage of the entitlement for the following operating hour.

(2) **Baseload product.**

(A) Description. For each baseload capacity entitlement, the scheduled power shall be provided to the entitlement holder during the month of the entitlement seven days per week and 24 hours per day, in accordance with the scheduling requirements and limitations provided in subparagraph (E) of this paragraph.

(B) Block size. Each baseload capacity entitlement shall be 25 MW in size.

(C) Fuel price. The fuel cost owed to the affiliated PGC by the entitlement holder for the dispatched baseload power will be the average cost of coal, lignite, and nuclear fuel, in dollars per MWh, based on the company's final ECOM model as determined in the proceeding pursuant to PURA §39.201 as projected for the relevant time period. Electric utilities without an ECOM determination in their proceeding conducted pursuant to PURA §39.201 shall propose for commission review an average cost of fuel in a similar manner.

(D) Starts per month. The entitlement holder of a baseload capacity entitlement shall take power from the entitlement seven days per week and 24 hours per day and is therefore not permitted to direct the affiliated PGC to make any starts of baseload capacity entitlements.

(E) Baseload scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement.

(ii) Timing of scheduling.

(I) The entitlement holder shall submit day-ahead schedules for the entitlement to the seller no later than 8:00 a.m. The daily capacity commitment is determined for a baseload entitlement by the 8:00 a.m. schedule.

(II) The entitlement holder may submit to the seller a revised day-ahead schedule for energy from the entitlement no later than noon, subject to the limit on maximum energy in clause (iv)(II) of this subparagraph.

(III) No hour-ahead schedules are permitted for energy from baseload entitlements.

(iii) Schedule content. Each schedule shall specify, for each scheduling interval, subject to the scheduling limits in clause (iv) of this subparagraph, the energy scheduled to be delivered to the entitlement holder from the entitlement.

(iv) Scheduling limits.

(I) Minimum energy. The entitlement holder may not schedule energy at less than 20 MW from the entitlement at any time during the month.

(II) Maximum energy. The entitlement holder may not schedule energy at any level greater than the daily capacity commitment in any scheduling interval.

(III) Maximum changes. Subject to the minimum energy rate specified in subclause (I) of this clause:

(-a-) Total. Generally, the rate at which energy is scheduled by the entitlement holder in each hour cannot change more than plus or minus two MW.

(-b-) Energy. Subject to the maximum change specified in item (-a-) of this subclause, the maximum change in energy scheduled from one scheduling interval to the next scheduling interval cannot exceed plus or minus two MW.

(v) Default schedule. If the entitlement holder does not submit a timely day-ahead schedule, as applicable, then the schedule for the applicable operating day shall be deemed to be, in every settlement interval of the applicable operating day, a total of 20 MW for the daily capacity commitment.

(F) Contract price for baseload. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment. The fuel price is as specified on the letter confirmation for the entitlement. The energy payment from the entitlement holder to the affiliated PGC is the fuel price in dollars per MWh specified in the letter confirmation for the entitlement times the greater of:

(I) The total energy scheduled from the entitlement during the entitlement month; or

(II) An amount of MWh equal to 20 MW times the number of hours in the entitlement month.

(G) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price to the affiliated PGC after receiving an invoice for that amount in accordance with the other terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the other terms of the Agreement.

(3) **Gas-intermediate product.**

(A) Description. For each gas-intermediate capacity entitlement, not less than 30% of the entitlement shall be provided to the entitlement holder at any time when any of the entitlement is being scheduled by the entitlement holder , with the remainder of the block scheduled as day-ahead shaped power in accordance with the scheduling requirements and limitations provided in subparagraph (E) of this paragraph.

(B) Block size. Each gas-intermediate capacity entitlement shall be 25 MW in size.

(C) Fuel price.

(i) Except as specified otherwise in clause (ii) of this subparagraph, the fuel cost owed to the affiliated PGC by the entitlement holder for the gas-intermediate capacity dispatched will be 10.850 MMBtu per MWh heat rate times the minimum MWh that shall be taken for gas-intermediate capacity as required in subparagraph (A) of this paragraph times the first-of-the-month index posted in the publication "Inside FERC" for the Houston Ship Channel for the month of the entitlement. For power dispatched above the minimum MWh required, the additional fuel price owed to the affiliated PGC will be 10.850 MMBtu per MWh times the MWh of gas-intermediate power dispatched pursuant to the entitlement above the minimum requirement times the daily gas price.

(ii) EGSI.

(I) For EGSI gas-intermediate capacity in the eastern congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-intermediate capacity dispatched will be 10.850 MMBtu per MWh heat rate times the minimum MWh that shall be taken for gas-intermediate capacity as required in subparagraph (A) of this paragraph times the first-of-the-month index posted in the publication "Inside FERC" for Henry Hub for the month of the entitlement. For power dispatched above the minimum MWh required, the additional fuel price owed to the affiliated PGC will be 10.850 MMBtu per MWh times the MWh of gas-intermediate power dispatched pursuant to the entitlement above the minimum requirement times the Henry Hub daily gas price.

(II) For EGSI gas-intermediate capacity in the western congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-intermediate capacity dispatched will be 10.850 MMBtu per MWh heat rate times the minimum MWh that shall be taken for gas-intermediate capacity as required in subparagraph (A) of this paragraph times the average of the first-of-the-month index posted in the publication "Inside FERC" for Henry Hub for the month of the entitlement and the first-of-the-month index posted in the publication "Inside FERC" for the Houston Ship Channel for the month of the entitlement. For power dispatched above the minimum MWh required, the additional fuel price owed to the affiliated PGC will be 10.850 MMBtu per MWh times the MWh of gas-intermediate power dispatched pursuant to the entitlement above the minimum requirement times the average of the Henry Hub daily gas price and the Houston Ship Channel daily gas price.

(D) Starts per month. The entitlement holder of gas-intermediate capacity shall take a minimum of 30% of the power from the entitlement in each interval and is therefore not permitted to direct the affiliated PGC to make any starts of gas intermediate capacity entitlements.

(E) Gas-intermediate scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement.

(ii) Timing of scheduling.

(I) The entitlement holder shall submit day-ahead schedules for the entitlement to the seller no later than 8:00 a.m. The daily capacity commitment is determined for a gas-intermediate entitlement by the 8:00 a.m. schedule.

(II) The entitlement holder may submit to seller a revised day-ahead schedule for energy from the entitlement no later than noon, subject to the limit on maximum energy in clause (iv)(II) of this subparagraph.

(III) No hour-ahead schedules are permitted for energy from gas-intermediate entitlements.

(iii) Schedule content. Each schedule shall specify, for each scheduling interval, the energy scheduled to be delivered to the entitlement holder from the entitlement.

(iv) Scheduling limits.

(I) Minimum energy. The entitlement holder may not schedule energy at less than eight MW from the entitlement at any time during the month.

(II) Maximum energy. The entitlement holder may not schedule energy at a level greater than the daily capacity commitment in any scheduling interval.

(III) Maximum changes. Subject to the minimum energy rate specified in subclause (I) of this clause and the maximum energy rate specified in subclause (II) of this clause, the energy scheduled by the entitlement holder in each hour cannot change more than plus or minus six MW.

(v) Default schedule. If the entitlement holder does not submit a timely day-ahead schedule, as applicable, then the schedule for the applicable operating day shall be deemed to be, in every settlement interval of the applicable operating day, a total of eight MW for the daily capacity commitment. This deemed schedule may not be changed in any hour-ahead schedule.

(F) Contract price for gas-intermediate. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment from the entitlement holder to the affiliated PGC is the sum, for each settlement interval in the entitlement month, of the minimum energy payment and the excess energy payment.

(-a-) The minimum energy payment is the product of eight MWh times the minimum fuel price.

(-b-) The excess energy payment is the product, for each settlement interval, of the excess fuel price defined in subclause (II)(-b-) of this clause times energy scheduled.

(II) Fuel price.

(-a-) The minimum fuel price is the product of a heat rate equal to 10.850 MMBtu per MWh times the daily gas price.

(-b-) The excess fuel price is the product of a heat rate equal to 10.850 MMBtu per MWh times the daily gas price.

(G) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the terms of the Agreement.

(4) **Gas-cyclic product.**

(A) Description. The gas-cyclic entitlement shall be flexible day-ahead shaped power.

(B) Block size. Each gas-cyclic capacity entitlement shall be 25 MW in size.

(C) Fuel price.

(i) Except as specified otherwise in clause (ii) of this subparagraph, the fuel price owed to the affiliated PGC by the capacity entitlement holder for gas-cyclic capacity dispatched will be 12.100 MMBtu per MWh times the MWh of the gas-cyclic power dispatched under the entitlement times the daily gas price.

(ii) EGSI.

(I) For EGSI gas-cyclic capacity in the eastern congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-cyclic capacity dispatched will be 12.100 MMBtu per MWh times the MWh of gas-cyclic power dispatched under the entitlement times the Henry Hub daily gas price.

(II) For EGSI gas-cyclic capacity in the western congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-cyclic capacity dispatched will be 12.100 MMBtu per MWh times the MWh of gas-cyclic power dispatched under the entitlement times the average of the Henry Hub daily gas price and the Houston Ship Channel daily gas price.

(D) Starts per month and associated costs. The entitlement holder of gas-cyclic capacity shall be entitled to direct the selling affiliated PGC to make up to the amount of starts per month of each entitlement of gas-cyclic capacity allowed pursuant to subparagraph (E)(v) of this paragraph.

(E) Gas-cyclic scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement.

(ii) Timing of scheduling.

(I) The entitlement holder shall submit day-ahead schedules for the entitlement to seller no later than 8:00 a.m. The daily capacity commitment is determined for a gas-cyclic entitlement by the 8:00 a.m. schedule, unless the entitlement holder notifies seller, in the schedule, that it is exercising its option to set the daily capacity commitment in the last schedule submitted before the gas-cyclic start deadline pursuant to subclause (IV) of this clause.

(II) The entitlement holder may submit to seller a revised day-ahead schedule for energy from the entitlement no later than noon, subject to the limit on maximum energy in clause (iv)(II) of this subparagraph.

(III) No hour-ahead schedules are permitted for energy from gas-cyclic entitlements.

(IV) The gas-cyclic start deadline for declaring the daily capacity commitment for each settlement interval in an operating hour is 15 hours before the start of the operating hour.

(iii) Schedule content. Each schedule shall specify, for each scheduling interval, the energy scheduled to be delivered to the entitlement holder from the entitlement.

(iv) Scheduling limits.

(I) Minimum energy. The entitlement holder may not schedule energy at any level between zero MW and five MW from the entitlement at any time during the month.

(II) Maximum energy. The entitlement holder may not schedule energy at any level greater than the daily capacity commitment in any scheduling interval.

(III) Maximum changes. Subject to the minimum energy rate specified in subclause (I) of this clause and the maximum energy rate specified in subclause (II) of this clause, the energy scheduled by the entitlement holder in each hour cannot change more than plus or minus six MW.

(v) Starts. The entitlement holder shall not direct more than 20 starts during the month of the entitlement, and the entitlement holder shall not direct more than one start per day. A start occurs every time a schedule increases the MW of energy from zero MW. Once the maximum number of starts have occurred during the entitlement, the energy scheduled by the entitlement holder may not be lower than a rate of five MW unless that level is lowered to zero MW, at which time the level may not be raised above zero MW for the remainder of the month.

(vi) Default schedule. If the entitlement holder does not submit a timely day-ahead schedule as applicable, then the schedule for the applicable operating day is deemed to be, in every settlement interval of the applicable operating day, zero MW for the daily capacity commitment and zero MW of energy. This deemed schedule may not be changed.

(F) Contract price for gas-cyclic. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment for each settlement interval from the entitlement holder to the affiliated PGC is the product, of the fuel price defined in subclause (II) of this clause times energy scheduled.

(II) Fuel price.

(-a-) The fuel price, for the portion of the daily capacity commitment that is designated by the entitlement holder by 8:00 a.m. in the day-ahead schedule, is the product of a heat rate equal to 12.100 MMBtu per MWh times the daily gas price.

(-b-) The fuel price for the portion of the daily capacity commitment that is not released or committed at 8:00 a.m., but committed before the gas-cyclic start deadline, is the product of a heat rate equal to 12.100 MMBtu per MWh times (the sum of the daily gas price plus $ 0.25.)

(G) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the terms of the Agreement.

(5) **Gas-peaking product.**

(A) Description. The gas-peaking entitlement shall be intra-day power.

(B) Block size. Each gas-peaking capacity entitlement shall be 25 MW in size.

(C) Fuel price.

(i) Except as specified in clause (ii) of this subparagraph, the fuel price owed to the affiliated PGC by the entitlement holder for gas-peaking capacity dispatched will be 14.100 MMBtu per MWh times the MWh of the gas-peaking power dispatched under the entitlement times the daily gas price.

(ii) EGSI.

(I) For EGSI gas-peaking capacity in the eastern congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-peaking capacity dispatched will be 14.100 MMBtu per MWh times the MWh of gas-peaking power dispatched under the entitlement times the Henry Hub daily gas price.

(II) For EGSI gas-peaking capacity in the western congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-peaking capacity dispatched will be 14.100 MMBtu per MWh times the MWh of gas-peaking power dispatched under the entitlement times the average of the Henry Hub daily gas price and the Houston Ship Channel daily gas price.

(D) Starts per month and associated costs. The entitlement holder of gas-peaking capacity shall be entitled to direct the selling affiliated PGC to make unlimited starts per month of each entitlement of gas-peaking capacity.

(E) Gas-peaking scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement and may submit hour-ahead schedules.

(ii) Timing of scheduling.

(I) The entitlement holder shall submit day-ahead schedules for the entitlement to the seller no later than 8:00 a.m. The daily capacity commitment is determined for a gas-peaking entitlement by the 8:00 a.m. schedule, unless the entitlement holder notifies the seller, in the schedule, that it is exercising its option to set the daily capacity commitment in the last schedule submitted before the gas-peaking start deadline defined in subclause (III) of this clause. The entitlement holder shall submit hour-ahead schedules for the entitlement to the seller no later than one hour before the start of the operating hour.

(II) The entitlement holder may submit to the seller a revised day-ahead schedule for energy from the entitlement no later than noon.

(III) The gas-peaking start deadline for declaring the daily capacity commitment for each operating hour is two hours before the beginning of the operating hour.

(iii) Schedule content. Each schedule shall specify, for each scheduling interval, the energy scheduled to be delivered to the entitlement holder from the entitlement.

(iv) Scheduling limits.

(I) The rate at which energy is scheduled by the entitlement holder in each scheduling interval during one hour shall be either zero MW or 25 MW and cannot change during the hour.

(II) Subject to the requirement of subclause (I) of this clause, if the entitlement holder schedules any energy from the entitlement in one hour, the rate at which energy is scheduled shall continue uninterrupted at a level of 25 MW for not less than four hours.

(III) Subject to the requirements of subclause (I) and (II) of this clause, when the entitlement holder decreases a schedule for energy to zero MW from the entitlement in one hour, the energy scheduled shall continue uninterrupted at a level of zero MW for not less than two hours.

(v) Default Schedule. If the entitlement holder does not submit a timely day-ahead schedule then the schedule for the applicable operating day shall be deemed to be, in every settlement interval of the applicable operating day, zero MW for the daily capacity commitment and zero MW of energy. This deemed schedule may not be changed in any revised day-ahead schedule, or in any hour-ahead schedule.

(F) Contract price for gas-peaking. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment for each settlement interval from the entitlement holder to the affiliated PGC is the product of the fuel price defined in subclause (II) of this clause times energy scheduled.

(II) Fuel price.

(-a-) The fuel price, for operating days for which the entitlement holder designated its daily capacity commitment by 8:00 a.m.

in the day-ahead schedule, is the product of a heat rate equal to 14.100 MMBtu per MWh times the daily gas price.

(-b-) The fuel price, for operating days for which the entitlement holder exercised its option to designate its daily capacity commitment after 8:00 a.m. and before the gas-peaking start deadline, is the product of a heat rate equal to 14.100 MMBtu per MWh times (the sum of the daily gas price plus $ .25).

(G) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the terms of the Agreement.

(6) **Scheduling discrepancies.** If the entitlement holder submits a schedule to seller for an entitlement that violates any of the scheduling requirements for that capacity auction product type, the schedule shall be deemed a non-conforming schedule for a scheduled hour. The schedule for that non-conforming scheduled hour shall then be deemed to be the same as the schedule for the nearest preceding hour for which the schedule was not a non-conforming schedule. The seller shall promptly notify the entitlement holder of a non-conforming schedule.

(7) **Ancillary services.** Until such time that all ancillary services issues are addressed and resolved within the context of a Federal Energy Regulatory Commission (FERC) approved regional transmission organization, entitlements will include rights only to energy and capacity as described in this subsection and specifically exclude any ancillary services rights. Such exclusion is consistent with subsection (e)(1) of this section, which allows products other than those described in this subsection to be offered with good cause. In the interim, the affiliated PGC shall provide the required ancillary services to eligible customers at the current FERC-approved rates.

(h) **Auction process.**

(1) **Timing issues**.

(A) **Frequency of auctions**.

(i) Auction dates. Capacity auctions shall begin on March 10, July 10, September 10, and November 10 of each year. If the date for an auction start falls on a weekend or banking holiday, then that auction shall begin on the first business day after the weekend or banking holiday.

(ii) Simultaneous auctions. Auctions for a product will be held simultaneously by all affiliated PGCs of entitlements within the respective North American Electric Reliability Council (NERC) regions in Texas. For example, ERCOT and non-ERCOT auctions can be held at different times and dates.

(iii) Termination of the capacity auction process. The obligation of an affiliated PGC to auction entitlements shall continue until the earlier of 60 months after the date customer choice is introduced or the date the commission determines that 40% or more of the electric power consumed by residential and small commercial customers within the affiliated transmission and distribution utility's certificated service area before the onset of customer choice is provided by nonaffiliated retail electric providers. The determination of the 40% threshold shall be as prescribed by the commission's rule relating to the price to beat.

(B) Auction conclusion.

(i) Receipt of bids. In order for an affiliated PGC that is auctioning capacity to consider a bid, the bid must be received by that affiliated PGC by close of the round for which the bid is to be submitted.

(ii) Concluding each individual auction. The affiliated PGC shall provide notice of the winning bid(s) to auction participants and the commission by the close of business on the first day after the auction closes that is not a weekend or banking holiday.

(iii) Confidentiality and posting of bids. The affiliated PGC shall designate non-marketing personnel to evaluate the bids, and persons reviewing the bids shall not disclose the bids to any person engaged in marketing activities for the affiliated PGC or use any competitively sensitive information received in the bidding process. Upon announcement of the winning bids, the affiliated PGC shall provide the commission and all auction participants information on the quantity of each product requested by bidders during each round of an auction, but shall not divulge the identity of any particular bidders. Upon specific request by the commission, and under standard protective order procedures, the utility shall provide the identity of the bidders to the commission.

(iv) The affiliated PGC shall be deemed to have met the 15% requirement if it offered products in a product category (for example, gas-intermediate) and successfully sold, at least, all of the entitlements offered in one particular month, in that product category. If there is no month in which all of the products in a product category are sold, the affiliated PGC shall comply with the provisions of paragraph (7)(C) of this subsection.

(2) **Auction administration.**

(A) Each auction shall be administered by the affiliated PGC selling the entitlement. An affiliated PGC or group of affiliated PGCs may retain the services of a qualified third-party to perform the auction administration functions.

(B) Notice of capacity available for auction.

(i) Method of notice. At least 60 days before each auction start date, each affiliated PGC offering capacity entitlements at auction shall file with the commission notice of the pending auction. Within 20 days of the filing of the notice, interested parties may provide comments on the affiliated PGC's proposed notice. If no comments are received, the affiliated PGC's proposed notice shall be deemed appropriate. If any party objects to the affiliated PGC's proposed notice, then the commission shall administratively approve, reject, or approve the notice with modifications. With respect to the September 10, 2003 auction:

(I) Affiliated PGC's shall include a reference to Project Number 27826, *Rulemaking Proceeding to Require Another Set of Two-Year Strips Under the Capacity Auction Rule, §25.381*, in their 60-day notice with a statement that the products to be auctioned in the September 2003 auction will not be fully known until after the commission finalizes Project Number 27826; and

(II) Within five days after the rule amendment in Project Number 27826 becomes effective, affiliated PGC's shall revise their notice, with sufficient explanation, to accurately reflect the products to be auctioned.

(ii) Contents of notice.

(I) The auction notice shall include the auction start date, the date and time by which bids must be received for the first round, and the types, quantity (number of blocks), congestion zone, and term of each entitlement available in that auction. The notice shall also include the following range of bid increments for each product type to be used to adjust the price of entitlements between rounds of the auction:

(-a-) Baseload - $ .05 to $ .75;

(-b-) Gas-intermediate - $ .02 to $ .30;

(-c-) Gas-cyclic - $ .02 to $ .30;

(-d-) Gas-peaking - $ .02 to $ .30.

(II) The affiliated PGC shall also specify which power generation units will be used to meet the entitlement for each type of entitlement to be auctioned. If baseload entitlements are being auctioned, the utility shall also specify the fuel cost prescribed in subsections (f)(3)(B)(ii) and (g)(2)(F)(ii) of this section at the time of the auction. If an entitlement to be auctioned is subject to the forced outage provision in subsection (e)(2)(B) of this section, then the notice must include the applicable three-year rolling average of the forced outage rate.

(iii) The affiliated PGCs shall publish their respective notices and application forms on their web sites no later than 45 calendar days before the start of each auction. Each entity that intends to bid in an affiliated PGC's auction shall complete the forms, which include the first page of the cover sheet to the Agreement, and submit them to the affiliated PGC at least 20 business days before the auction starts, to allow enough time for evaluation and approval of credit. Potential bidders may submit the required documents after that time, but at the risk of not having credit and document approval in time for them to participate in the auction.

(iv) Credit approval for entities bidding on capacity auction products in ERCOT or in non-ERCOT areas of Texas will be performed pursuant to subsection (e)(7) of this section.

(v) The affiliated PGC shall notify an approved bidder of its available credit and send the approved bidder a completed capacity auction-specific version of the applicable Agreement, executed by the affiliated PGC, within ten business days after the bidder has submitted the required information. The approved bidder should attempt to execute and return the executed Agreement to the affiliated PGC no later than five business days before the auction starts. The executed Agreement shall be received by the affiliated PGC no later than two business days before the auction starts. The affiliated PGC shall provide a password or passwords to the approved bidder to allow access to the auction web site and to allow it to bid no later than one business day before the auction starts. An approved bidder may not request or receive additional credit after the auction starts.

(vi) Specific information on how to place bids and navigate the auction sites will be provided by the affiliated PGCs to their qualified bidders prior to the beginning of the capacity auction.

(3) **Term of auctioned capacity.**

(A) Initial auction. For the initial auction in September 2001, each entitlement was one month in duration, with:

(i) Approximately 20% of the entitlements auctioned as two one-year strips with the strips auctioned jointly (the 12 months of 2002 and 2003),

(ii) Approximately 30% of the entitlements as one-year strips (the 12 months of 2002), and

(iii) Approximately 20% of the entitlements as discrete months for each of the 12 months of 2002 (January through December of 2002)

(iv) Approximately 30% of the entitlements as discrete months for the first four months of 2002 (January through April of 2002).

(v) Reductions in the amounts of entitlements available during the months of March, April, May, October, and November of each calendar year shall be accounted for in the entitlements offered as discrete months.

(B) Schedule of subsequent auctions.

(i) The auction in March of a year will auction approximately 30% of the entitlements as the discrete months of May through August of that year.

(ii) The auction in July of a year will auction approximately 30% of the entitlements as the discrete months of September through December of that year.

(iii) The auction in September of a year will auction:

(I) Approximately 50% of the entitlements as the one-year strips for the next year; and

(II) Approximately 20% of the entitlements as discrete months for each of the 12 calendar months of the next year.

(iv) The auction in November of a year will auction approximately 30% of the entitlements as the discrete months of January through April of the next year.

(v) Reductions in the amounts of entitlements available during the months of March, April, May, October, and November of each calendar year shall be accounted for in the entitlements offered as discrete months.

(vi) The commission will periodically evaluate the need to sell one-year and two-year strips and make appropriate adjustments to the terms of the auctions.

(C) Modification of term. If the auction is for a one-year or two-year strip term and the affiliated retail electric provider (REP) expects to reach the 40% load loss threshold in paragraph (1)(A)(iii) of this subsection, the affiliated PGC may request a shorter term strip by providing evidence of the loss of customer load. Similarly, prior to an auction for the next four available months, an affiliated PGC may request to not auction months in which it projects reaching the 40% threshold. Such filings shall be made 90 days before the auction start date. An affiliated PGC that will satisfy its auction requirements through divestiture, as described in subsection (d) of this section may petition the commission to set an appropriate term for entitlements. The affiliated PGC may not adjust the amount or length of an entitlement to be auctioned except as authorized by the commission.

(4) Quantity to be auctioned.

(A) Block size and number of blocks. The block size of the auctioned capacity entitlement is 25 MW. The affiliated PGC shall divide the amount determined for each product referenced in subsection (e)(1) of this section by 25 to determine the number of blocks of each type to be auctioned.

(B) Divisibility. If the amount to be auctioned for an affiliated PGC for a particular product is not evenly divisible by 25, any remainder shall be added to the product most highly valued in the immediately preceding auction for products of the same duration and shall increase by one the number of entitlements of that product.

(C) Total amount. The sum of the blocks of capacity auctioned shall total no less than 15% of the affiliated PGC's Texas jurisdictional installed generation capacity.

(5) **Bidders**. For each auction, potential bidders shall pre-qualify by demonstrating compliance with the credit requirements in subsection (e)(7) of this section in advance of submission of a bid.

(6) **Bidding procedures.** For purposes of this section, the term "set of entitlements" shall refer to all of a seller's products of the same type and period. For example, a quantity of baseload products sold as a one-year strip for 2002 would be a set of baseload-annual 2002 entitlements, while a quantity of baseload products sold as the discrete month of July 2002 would be a set of baseload-July 2002 entitlements.

(A) Method of auction for affiliated PGCs within ERCOT. Each auction shall be a simultaneous, multiple round, auction that includes procedures that allow switching by bidders between affiliated PGCs and product types.

(i) Auction duration. Once a product auction commences it will continue through each business day until that auction concludes.

(ii) Round duration. Each auction's first round will begin promptly at 8:00 a.m. and each round will last for 30 minutes with 30 minutes between rounds. For example, the first round of bidding will start at 8:00 a.m. and end at 8:30 a.m., the second round will start at 9:00 a.m. and end at 9:30 a.m., etc. No round may start later than 4:00 p.m. All times are in central prevailing time.

(iii) Credit calculation. An entitlement bidder's credit limit shall be adjusted during the auction based on the value of the entitlements bid upon, and will be determined by using an assumed fuel price stated by the entitlement seller, and the capacity price for the lesser of three months or the duration of the entitlement plus the amount that would be paid to exercise the entitlement for the lesser of three months or the duration of the entitlement at the assumed dispatch for each product as follows:

Product	**Peak Months (May-Sept.)**	**Off-Peak Months (Oct.-April)**
Baseload	100%	90%
Gas-intermediate	50%	20%
Gas-cyclic	20%	10%
Gas-peaking	10%	2%

(B) Mechanism for auction for affiliated PGCs within ERCOT. Each affiliated PGC shall conduct the auction over the Internet on a secure web page and shall assign a password and bidder's number to each entity that has satisfied the credit requirements in this section.

(C) Method of auction for affiliated PGCs in non-ERCOT areas. Each auction shall be a simultaneous, multiple round, open bid auction.

(i) First round. For the first round of the auction, the affiliated PGC will post the opening bid price determined in accordance with paragraph (7) of this subsection for each set of entitlements available for purchase at the auction. Each bidder will specify the number of entitlements it wishes to purchase of each set of entitlements at the opening bid price(s). If the total demand for a set of entitlements is less than the available quantity of the set of entitlements, the price for each of the entitlements in the set will be the opening bid price and each bidder in the round will receive all of the entitlements in the set they demanded. Any remaining entitlements of the set will be held for future auction as noticed by the affiliated PGC in accordance with its notice given pursuant to paragraph (7) of this subsection.

(ii) Subsequent rounds. If the total demand for a set of entitlements in any round is more than or equal to the available quantity, the affiliated PGC will adjust the price upward within the range for each specific product type as noticed according to paragraph (2)(B)(ii)(I) of this subsection. Bidders shall then submit bids for the quantities they wish to purchase of each set of entitlements at the new price. Subsequent rounds shall continue until demand is less than supply for each set of entitlements. The auction then closes and the market clearing price for each set of entitlements is set at the last price for which demand equaled or exceeded supply. Bidders shall then be awarded the entitlements they demanded in the final round, plus a pro-rata share of any entitlements they demanded in the next to last round as described in clause (iii) of this paragraph.

(iii) Pro-rata entitlement allocation. The pro-rata allocation of entitlements will be implemented by determining a bid differential between the next-to-last round bid and the number of awarded entitlements based on the last round and awarding the remaining entitlement to the bidder with the largest differential. The awarded entitlement will then be subtracted from that bidder's differential and the process will iterate until all entitlements have been awarded. In the event that the differential between two or more bidders is the same, the tie will be broken based on the timestamp of each bidder's last bid submitted in the next-to-last round. For example, 14 baseload one-year strip entitlements are available and bidders A, B, C, and D are bidding. In the last round, demand was only 11 entitlements and bidder D did not bid.

Bidders	**Bids Next-To-Last Round**	**Last Round Bid**	**Awarded**	**Differential Between Rounds**
A	4 - 10:50	3	3	1
B	6 - 10:20	6	6	0
C	3 - 10:44	2	2	1
D	3 - 10:59	None - 0	-	3
Total	**16**	11 (3 leftover)	**11 (3 avail)**	
In this example, bidder "D" would receive the first unsubscribed entitlement and its differential would be reduced by one since it possesses the largest differential.				

Bidders	**Bids Next-To-Last Round**	**Last Round Bid**	**Awarded**	**Differential Between Rounds**
A	4 - 10:50	3	3	1
B	6 - 10:20	6	6	0
C	3 - 10:44	2	2	1
D	3 - 10:59	None - 0	**1**	**2**
Total	**16**	**11 (3 leftover)**	**12 (2 avail)**	
Since bidder "D" still contains the largest differential and there are still two unsubscribed entitlements, "D" will again be awarded an entitlement.				

BIDDERS	**Bids Next-To-Last Round**	**Last Round Bid**	**Awarded**	**Differential Between Rounds**
A	4 - 10:50	3	3	1
B	6 - 10:20	6	6	0
C	3 - 10:44	2	2	1
D	3 - 10:59	None - 0	**2**	**1**
Total	**16**	**11 (3 leftover)**	**13 (1 avail)**	

For the last remaining entitlement there are three bidders that all have a differential of one: "A", "C", and "D". Therefore, a tie exists and the timestamp tiebreaker will be used to determine which of the three bidders should receive the entitlement. Based on the timestamps bidder "C" would receive the last entitlement, because it has the earliest time stamp in the next-to-last round. The completed auction would appear as follows:

Bidders	**Bids Next-To-Last Round**	**Last Round Bid**	**Awarded**	**Differential Between Rounds**
A	4 - 10:50	3	3	1
B	6 - 10:20	6	6	0
C	3 - 10:44	2	**3**	0
D	3 - 10:59	None - 0	2	1
Total	**16**	**11 (3 leftover)**	**14 (0 avail)**	

(iv) Auction duration. Once a product auction commences it will continue through each business day until that auction concludes.

(v) Round duration. Each auction's first round will begin promptly at 8:00 a.m. and each round will last for 30 minutes with 30 minutes between rounds. For example, the first round of bidding will start at 8:00 a.m. and end at 8:30 a.m., the second round will start at 9:00 a.m. and end at 9:30 a.m., etc. No round may start later than 4:00 p.m. All times are in central prevailing time.

(vi) Credit calculation. An entitlement holder's credit limit shall be adjusted during the auction based on the value of the entitlements awarded to the holder, which will be determined by using an assumed fuel price stated by the entitlement seller, and the capacity price for the lesser of three months or the duration of the entitlement plus the amount that would be paid to exercise the entitlement for the lesser of three months or the duration of the entitlement at the assumed dispatch for each product as follows:

Product	**Peak Months (May - Sept.)**	**Off-Peak Months (Oct. - April)**
Baseload	100%	90%
Gas-intermediate	50%	20%
Gas-cyclic	20%	10%
Gas-peaking	10%	2%

(D) Activity rules for affiliated PGCs in non-ERCOT areas.

(i) A bidder must bid in the first round for a particular entitlement to participate in subsequent rounds.

(ii) A bidder may not bid a greater quantity than it bid in a previous round for a particular entitlement.

(E) Mechanism for auction for affiliated PGCs in non-ERCOT areas. Each affiliated PGC shall conduct the auction over the Internet on a secure web page and shall assign a password and bidder's number to each entity that has satisfied the credit requirements in this section.

(7) **Establishment of opening bid price.**

(A) If an affiliated PGC intends to change the minimum opening bid prices that would otherwise be applicable under subparagraph (B) of this paragraph, it shall file with the commission, not less than 90 days before the auction start date on which the change is proposed to be applicable, a methodology for determining an opening bid price for each type of entitlement, if needed, based on the affiliated PGC's expected variable cost of operation, but excluding any return on equity. The opening price may not include any cost included in the fuel price to be paid by entitlement holders, nor any cost being recovered by its affiliated transmission and distribution utility through non-bypassable delivery charges, but may recover variable costs not included in the fuel prices, such as fuel service costs and start up fees. Parties shall have 30 days after filing to challenge the methodology. If no challenges are received, the affiliated PGC's proposed methodology shall be deemed appropriate. If any party objects to the affiliated PGC's proposed methodology, then the commission shall determine the appropriate methodology.

(B) Minimum opening bids for entitlements shall be the same as the minimum opening bids used in the most recent auction that included those entitlements, except that sellers with plants that have been affected by congestion zone changes since the most recent auction may use minimum opening bids that are different than the minimum opening bids in the most recent auction, provided that the seller maintains the same weighted-average, by MW, of the most recent auction's minimum bids, for all of its plants of the same product type in all congestion zones, to compute the new minimum opening bids for each product type. Nothing in this subparagraph shall prevent the commission from ordering a different methodology for a seller, if the seller proves that good cause exists for the change.

(C) In the notice provided pursuant to paragraph (2)(B)(i) of this subsection, the affiliated PGC may make available an opening bid price calculated pursuant to the commission-approved methodology for each type of entitlement to be offered for sale at auction. The affiliated PGC shall not be obligated to accept any bid for a product less than the opening bid price, but shall notify the commission that the opening bid price was not met. The affiliated PGC shall be deemed to have met the 15% requirement if it offered products in a product category (for example, gas-intermediate) and successfully sold, at least, all of the entitlements offered in one particular month, in that product category. If there is an auction where there is no month in which all of the entitlements of a particular product are sold, then the affiliated PGC shall, in its notice pursuant to paragraph (2)(B)(i) of this subsection, make a proposal to the commission in order to comply with the 15% requirement. The affiliated PGC's proposal may include revisions to the product category, product price, or offer alternative products for auction.

(8) **Results of the auction.** The results of the auction shall be simultaneously announced to all bidders by posting on the affiliated PGC's auction web site with posting of the market clearing price for each set of entitlements.

(i) **Resale of entitlement.**

(1) **Compliance with provisions.** An entitlement may be assigned, sold or transferred by the entitlement holder only by following the provisions of this section. Any purported assignment, sale, or transfer of an entitlement that does not follow the provisions of this section is void and ineffective against the affiliated PGC.

(2) **Eligible entities.** An entitlement holder may assign, sell, or transfer an entitlement to any person or entity other than an affiliated REP, but the entitlement holder may dispatch the output of the entitlement to an affiliated REP.

(3) **Obligations.** An entitlement that is assigned, sold, or transferred under this section remains subject to the provisions of the Agreement under which it originated, and the assignee of that entitlement succeeds to all of the rights and obligations of the assignor with respect to that entitlement.

(4) **Liability.** Neither the assignor nor any previous entitlement holder that has remained liable for payments due to the affiliated PGC in connection with the entitlement as a result of a previous assignment, sale, or transfer is released from liability to the affiliated PGC for payments due in connection with the entitlement unless:

(A) At least 14 days before the effective date of the assignment, sale, or transfer, assignee has provided security to the affiliated PGC that is equal to or greater than the security originally given to the affiliated PGC for the entitlement; and

(B) At least ten days before the effective date of the assignment, sale, or transfer, the affiliated PGC has notified both assignor and assignee in writing that the security has been approved and accepted by the affiliated PGC.

(5) **Requests to approve security.** The affiliated PGC shall respond to written requests to approve security to be offered by a prospective assignee within 14 days after receipt of that request. Approval shall not be unreasonably withheld.

(6) **Effective date.** No assignment, transfer, or sale of the entitlement by a party is binding on the non-assigning party until the non-assigning party receives written notice of the assignment, sale, or transfer and a copy of the executed assignment, sale, or transfer document, and the assignment, sale, or transfer is not effective unless such notice is received at least three days before the beginning of the entitlement month.

(j) **True-up process.**

(1) **Process.** For 2002 and 2003,the affiliated PGC shall reconcile, and either credit or bill to the transmission and distribution utility, any difference between the price of power obtained through the capacity auctions under this section and the power cost projections that were employed for the same time period in the ECOM model to estimate stranded costs for the affiliated PGC in the PURA §39.201 proceeding.

(2) **PGCs without stranded costs.** An affiliated PGC that does not have stranded costs described by PURA §39.254 is not required to comply with paragraph (1) of this subsection.

(3) Any order by the commission that finally resolves an affiliated PGC's stranded costs, prior to true-up, supersedes this subsection.

(k) **True-up process for electric utilities with divestiture**. If an affiliated PGC meets its capacity auction requirements through a divestiture as allowed by subsection (d) of this section, the proceeds of the divestiture shall be used for purposes of the true-up calculation.

(l) **Modification of auction procedures or products**. Upon a finding by the commission that the auction procedures or products require modification to better value the products or to better suit the needs of the competitive market, the commission may, by order, modify the procedures or products detailed in this section.

(m) **Contract terms.**

(1) **Standard agreement.** Parties shall utilize the Agreement in the form prepared by the Edison Electric Institute (Version 2.1). The Cover Sheet to the Agreement shall provide for credit terms that are based upon objective credit standards determined by the commission. There may be different versions of the Agreement applicable to sales of capacity auction products in different regions in Texas. For example, ERCOT and the non-ERCOT areas may have different versions of the Agreement.

(2) **Applicability.** The terms and conditions set forth in any Agreement apply only to the entitlements obtained in the capacity auctions under this section.

(3) **Electronic scheduling.** The Agreement shall require that, if the affiliated PGC provides an electronic scheduling interface for the dispatch of entitlements, then the entitlement holder shall schedule the dispatch of its entitlements using that electronic interface.

(4) **Scheduling discrepancies.** If an entitlement holder submits a non-conforming schedule to the affiliated PGC for an entitlement that violates any of the scheduling requirements for that capacity auction product type for a scheduled hour, then the schedule for that hour is deemed to be the same as the schedule for the hour most closely preceding that scheduled hour that was not a non-conforming schedule. The affiliated PGC shall promptly notify the entitlement holder of a non-conforming schedule. However, the requirements of this paragraph are subject to the default scheduling requirements for baseload and gas-intermediate products delineated in subsections (f)(3)(A)(iv)(V) and (f)(4)(A)(v) of this section for ERCOT areas, and subsections (g)(2)(E)(v) and (g)(3)(E)(v) of this section for non-ERCOT areas.

(5) **Alternative dispute resolution.** Alternative dispute resolution shall be a condition precedent to any right of any legal action regarding a dispute arising under, or in connection with, the standard agreement adopted by the commission. The parties may mutually agree to dispute resolution procedures. If the parties are unable to agree upon such procedures within five days after such dispute arises, the parties shall use the alternative dispute resolution procedures contained in the ERCOT protocols.

(6) **Seller's failure to fulfill obligation.** If an entitlement holder is assessed for imbalanced schedules, failure to procure ancillary services, or any other charges from ERCOT due to the failure of the affiliated PGC to fulfill the auctioned obligation, the affiliated PGC shall be responsible for these costs incurred by the entitlement holder.

§25.401. Share of Installed Generation Capacity.

(a) **Application.** The provisions of this section apply to power generation companies.

(b) **Share of installed generation capacity.** The percentage share of installed generation capacity for a power generation company will be determined by dividing the installed generation capacity owned and controlled by the power generation company in, or capable of delivering electricity to, a power region by the total installed generation capacity located in, or capable of delivering electricity to, the power region.

(c) **Capacity ratings.** For purposes of this section, generating unit capacity ratings shall be consistent with §25.91(f) of this title (relating to Generating Capacity Reports). The commission may revise reported capacity ratings if they are found to be incorrect.

(d) **Installed generation capacity of a power generation company.**

(1) In determining the percentage shares of installed generation capacity under the PURA §39.154, the commission shall combine capacity owned and controlled by a power generation company and any entity that is affiliated with that power generation company within the power region, reduced by the installed generation capacity of those facilities that are made subject to capacity auctions under PURA §39.153(a) and (d).

(2) In determining the percentage shares of installed generation capacity, the commission shall increase the installed generation capacity owned and controlled by a power generation company by the transmission import capability that is available for importing electricity during the summer peak season into the power region from generating facilities that are owned by the power generation company or an affiliate in another power region.

(3) In determining the percentage shares of installed generation capacity owned and controlled by a power generation company under PURA §39.154 and §39.156, the commission shall, for purposes of calculating the numerator, reduce the installed generation capacity owned and controlled by that power generation company by the installed generation capacity of any "grandfathered facility" within an ozone nonattainment area as of September 1, 1999, for which that power generation company has commenced complying or made a binding commitment to comply with PURA §39.264. This paragraph applies only to a power generation company that is affiliated with an electric utility that owned and controlled more than 27% of the installed generation capacity in the power region on January 1, 1999. The commission will consider a permit application to the Texas Natural Resource Conservation Commission (TNRCC) to be adequate evidence that the power generation company has commenced complying or made a binding commitment to comply with PURA §39.264. However, the commission will review the progress that has been made on achieving an approved an TNRCC permit, when it reviews and updates market share percentages, and if adequate progress has not been made, the commission may choose to include the grandfathered capacity in the numerator.

(e) **Total installed generation.** The total installed generation will consist of the installed generation capacity that is located in, or capable of delivering electricity to, a power region.

(1) Installed generation capacity will include all potentially marketable electric generation capacity. Except as provided in paragraph (2) of this subsection, installed generation capacity will include:

(A) generating facilities that are connected with a transmission or distribution system;

(B) generating facilities used to generate electricity for consumption by the person owning or controlling the facility;

(C) generating facilities that will be connected with a transmission or distribution system and operating within 12 months; and

(D) generating facilities that are located on the boundary between two power regions and are able to deliver electricity directly into either power region, except that the capacity of such facility shall be allocated between the power regions based on the share of its total electric energy that the facility sold in each power region during the preceding year.

(2) Installed generation capacity will not include generating facilities that have a nameplate rating equal to or less than 1 megawatt (MW).

(3) The amount of installed generation capacity that is capable of delivering electricity to a power region will be determined by:

(A) the import transmission capacity during the summer peak period of the alternating current transmission interconnections between the power region at issue and other power regions; and

(B) the import capacity during the summer peak period of the reliable direct current interconnections between the power region at issue and other power regions.

§25.421. Transition to Competition for a Certain Area Outside the Electric Reliability Council of Texas Region.

(a) **Purpose.** The purpose of this section is to address the process and the sequence of events for the introduction of retail competition in the portions of Texas served by El Paso Electric Company (EPE).

(b) **Application.** This section shall apply to an electric utility that is subject to Public Utility Regulatory Act (PURA) §39.102(c), namely EPE.

(c) **Readiness for retail competition.** The commission determines that the power region in which EPE is located will be unable to offer fair competition and reliable service to all retail customer classes in Texas upon the expiration of its system-wide rate freeze period in August 2005. Therefore, pursuant to PURA §39.103, the introduction of retail competition for the portions of the power region in Texas is delayed until this region can offer fair competition and reliable service to all retail customer classes.

(d) **Cost-of-service regulation.** Until the date on which EPE is authorized by the commission to implement retail competition pursuant to this section, its rates are subject to regulation under Chapter 36 of PURA.

(e) **Transition to competition.** The sequence of events set forth in paragraphs (1) through (5) of this subsection shall be followed to introduce retail competition in EPE's service territory. All the listed items in each stage must be completed before the next stage is initiated. Unless stated otherwise in the rule, each of the activities will be conducted by the commission in conjunction with EPE and other interested parties. Full retail competition will not begin in EPE's service territory until completion of the fifth stage.

(1) The first stage consists of the following activities:

(A) Develop and obtain approval of a regional transmission organization for the EPE region by the Federal Energy Regulatory Commission and commence independent operation of the transmission network under the approved regional transmission organization.

(B) Develop retail market protocols to facilitate retail competition.

(C) Complete an expedited proceeding to develop non-bypassable delivery rates for the customer choice pilot project to be implemented under paragraph (2)(A) of this subsection.

(2) The second stage consists of the following activities:

(A) Initiate the customer choice pilot project pursuant to PURA §39.104 and §25.431 of this title (relating to Retail Competition Pilot Projects).

(B) Develop a balancing energy market, market for ancillary services, and market-based congestion management system for the wholesale market in the region in which the regional transmission organization operates.

(C) Implement a seams agreement with adjacent power regions to reduce barriers to entry and facilitate competition.

(3) The third stage consists of the following activities:

(A) EPE shall:

(i) Prepare and file with the commission an application for business separation pursuant to PURA §39.051 and §25.342 of this title (relating to Electric Business Separation);

(ii) Prepare and file with the commission an application for unbundled transmission and distribution rates pursuant to PURA §39.201 and §25.344 of this title (relating to Cost Separation Proceedings);

(iii) Prepare and file with the commission an application for certification of a qualified power region pursuant to PURA §39.152; and

(iv) Prepare and file with the commission an application for price-to-beat rates pursuant to PURA §39.202 and §25.41 of this title (relating to Price to Beat).

(B) The activities to be completed by the commission in the third stage are to:

(i) Approve a business separation plan;

(ii) Set unbundled transmission and distribution rates;

(iii) Certify a qualified power region, which includes conducting a formal evaluation of wholesale market power in the region, pursuant to PURA §39.152;

(iv) Set price-to-beat rates for EPE; and

(v) Determine which competitive energy services must be separated from regulated utility activities pursuant to PURA §39.051 and §25.343 of this title (relating to Competitive Energy Services).

(C) The activity to be completed by the regional transmission organization, the statewide registration agent and market participants in the third stage is testing of retail and wholesale systems, including those systems necessary for switching customers to the retail electric provider of their choice and for settlement of wholesale market transactions.

(4) The fourth stage consists of the following activities:

(A) The commission shall evaluate the results of the pilot project pursuant to §25.431 of this title.

(B) EPE shall initiate capacity auctions pursuant to PURA §39.153 and §25.381 of this title (relating to Capacity Auctions) at a time to be determined by the commission.

(C) EPE shall separate competitive energy services from its regulated utility activities, in accordance with the commission order approving the separation of competitive energy services.

(5) The fifth stage consists of the commission evaluating whether the power region can offer fair competition and reliable service to all retail customer classes. If the commission concludes that the power region can offer fair competition and reliable service to all retail customer classes, it shall issue an order initiating retail competition and directing EPE to complete the business separation and unbundling.

(f) **Applicability of energy efficiency and renewable energy requirements.** Beginning January 1, 2006, EPE shall be subject to the energy efficiency requirements under PURA §39.905 and §25.181 of this title (relating to Energy Efficiency Goal) and the renewable energy credit requirements under PURA §39.904 and §25.173 of this title (relating to Goal for Renewable Energy).

(1) EPE shall begin administering the energy efficiency programs prescribed in §25.181 of this title by January 1, 2006. EPE shall meet, at a minimum, 5.0% of its growth in demand through energy efficiency savings resulting from these programs by January 1, 2007 and 10% of its growth in demand by January 1, 2008, and each year thereafter.

(2) EPE shall obtain, at a minimum, renewable energy credits in an amount sufficient to meet the requirements for the compliance period beginning January 1, 2006, and for each compliance period thereafter.

(g) **Applicability of other rules.** This section governs the implementation of PURA Chapter 39 requirements as applied to EPE. If there is an inconsistency or conflict between this section and other rules in this Chapter (relating to Substantive Rules Applicable to Electric Service Providers), the provisions of this section shall control.

(h) **Good cause.** Upon a finding of good cause, as determined by the commission, the sequence for retail competition set forth in subsection (e) of this section may be modified by commission order.

§25.422. Transition to Competition for Certain Areas within the Southwest Power Pool.

(a) **Purpose.** The purpose of this section is to address the process and the sequence of events for the introduction of retail competition in the Southwestern Electric Power Company service area in Texas (SWEPCO) and in the Southwest Power Pool portion of the AEP Texas North Company service area in Texas (Texas North-SPP).

(b) **Application.** This section shall apply to SWEPCO and Texas North-SPP (collectively referred to as "the utilities"). In the event that the customers, facilities, and the service area of Texas North-SPP are transferred to SWEPCO, the requirements of this section shall apply to the combined company.

(c) **Readiness for retail competition.** The commission determines that the power region in which SWEPCO and Texas North-SPP are located will be unable to offer fair competition and reliable service to all retail customer classes in Texas until January 1, 2011, at the earliest. Therefore, pursuant to Public Utility Regulatory Act (PURA) §39.103, the introduction of full retail competition for these portions of the power region in Texas shall be further delayed until this region can offer fair competition and reliable service to all retail customer classes, subject to the terms and conditions established in this section.

(d) **Cost-of-service regulation.** Until the date authorized by the commission for the implementation of full retail competition in SWEPCO and Texas North-SPP pursuant to this section, the rates of the utilities are subject to regulation under PURA Chapter 36. Until full retail competition begins, the utilities shall file Annual Earnings Reports as required by §25.73 of this title (relating to Financial and Operations Reports) in lieu of the Annual Report required by PURA §39.257.

(e) **Transition to competition.** Full retail competition shall not be introduced in the utilities' service areas before January 1, 2011. In addition, the introduction of retail competition in the utilities' service areas shall be conditioned on successful fulfillment of the sequence of events and activities set forth in paragraphs (1) through (5) of this subsection. All the listed items in each stage must be completed before the next stage is initiated. Unless stated otherwise in this section, each of the activities will be conducted by the commission in conjunction with SWEPCO and Texas North-SPP and other interested parties. Full retail competition will not begin in SWEPCO and Texas North-SPP until completion of the fourth stage.

- (1) **Completed Activities.** The stages outlined below assume that the following activities have been completed, by SWEPCO and Texas North-SPP:
  - (A) The initiation of a pilot program, including the establishment of rates for the pilot program.
  - (B) The filing of a business separation plan and unbundled cost of service.
  - (C) The separation of competitive energy services.
  - (D) Approval by the Federal Energy Regulatory Commission (FERC) of a regional transmission organization for the power region containing the utilities' service areas and the commencement of independent operation of the transmission network that ensures non-discriminatory access, by the approved regional transmission organization.
- (2) **Stage one.** The first stage consists of the following activities:
  - (A) The utilities will continue the operation of the pilot projects to a point that competitive retail electric providers are providing service to a reasonable number of customers for all major customer classes in the pilot program offered in the utilities' service areas;
  - (B) The utilities will file a plan for the development of retail market protocols to facilitate retail competition;
  - (C) The utilities will file a plan for the development of a balancing energy market, market for ancillary services, and market-based congestion management system for the wholesale market in the region in which the regional transmission organization operates; and

(D) A seams agreement will be implemented with adjacent power regions to reduce barriers to entry and facilitate competition.

(3) **Stage two.** The second stage consists of the following activities:

(A) The utilities shall file a transition to competition plan identifying how they intend to achieve full customer choice, including:

(i) certification of a qualified power region under PURA §39.152;

(ii) auctioning rights to generating capacity;

(iii) the establishment of a price to beat for eligible residential and commercial customers, including all necessary information for the derivation of the price to beat;

(iv) the retail market protocols that will be applicable in the utilities' service areas;

(v) a plan, developed with the regional transmission organization, the statewide registration agent, and market participants, for testing retail and wholesale systems, including those systems necessary for switching customers to the retail electric provider of their choice and for settlement of wholesale market transactions;

(vi) any necessary amendments to the previously filed business separation plan; and

(vii) an unbundled cost of service rate filing package.

(B) The activities to be completed by the commission in the second stage are to:

(i) Approve, modify, or reject the transition to competition plan within 180 days after the date of filing unless a hearing is requested. If a hearing is requested, the 180-day deadline shall be extended one day for each day of hearing;

(ii) Approve a business separation plan or amendments to the business separation plan;

(iii) Set unbundled transmission and distribution rates;

(iv) Certify a qualified power region for an area that includes the utilities, pursuant to PURA §39.152; and

(v) Set price-to-beat rates for the utilities' service areas.

(4) **Stage three.** The third stage consists of the following activities:

(A) The commission shall evaluate the results of the pilot projects pursuant to §25.431 of this title (relating to Retail Competition Pilot Projects), including whether the pilot project has progressed to a point that competitive retail electric providers are providing service to a reasonable number of customers for all major customer classes in the pilot programs offered in the utilities' service areas and whether the retail and wholesale systems have been tested and are performing adequately.

(B) The utilities shall initiate capacity auctions pursuant to PURA §39.153 and §25.381 of this title (relating to Capacity Auctions) at a time to be determined by the commission, and consistent with the transition to competition plan.

(5) **Stage four.** The fourth stage consists of the following activities:

(A) The utilities shall file a request for approval to commence competition, consistent with the procedures and standards developed in the previous stages. This filing should be made at least 180 days before the anticipated date of the commencement of competition.

(B) The commission shall evaluate whether the power region can offer fair competition and reliable service to all retail customer classes, and whether there are any outstanding items in the competition plan that must be completed prior to the commencement of full competition. If the commission concludes that the power region can offer fair competition and reliable service to all retail customer classes, it shall issue an order initiating retail competition consistent with the approved transition to competition plan.

(f) **Annual Report.** If full retail competition has not been implemented by January 1, 2011, the utilities shall file a report with the commission by January 31, 2011, identifying the items required by this section that have not yet been completed and an estimate of when completion of each item is anticipated. The utilities shall make a similar filing each year on January 31 until full retail competition in their service areas is authorized by the commission or the commission rules that no further reports are necessary.

(g) **Pilot Project Continuation.** Notwithstanding the provisions of subsection (e) of this section, the pilot projects in the utilities' service areas shall continue. However, so long as the utilities can effectively administer customer registrations and convey information relating to a customer's choice of retail electric provider and meter information to persons who need such information, they may continue to perform these functions, subject to the codes of conduct.

(h) **Protection of Contractual Rights.** The transition to competition plan in the utilities' service areas shall not adversely affect the rights or obligations of an electric cooperative under a wholesale generation or transmission agreement.

(i) **Energy efficiency and renewable energy requirements.** Effective January 1, 2007, SWEPCO and Texas North-SPP shall:

(1) Be subject to requirements of PURA §39.905 and §25.181 of this title (relating to Energy Efficiency Goal) and shall continue to participate in the required energy efficiency programs.

(2) Be subject to the requirements of PURA §39.904 and §25.173 of this title (relating to Goal for Renewable Energy) and shall continue to participate in the renewable energy credits program.

(j) **Applicability of other sections.** This section governs the implementation of PURA Chapter 39 requirements as applied to SWEPCO and Texas North-SPP. If there is an inconsistency or conflict between this section and other sections in this Chapter (relating to Substantive Rules Applicable to Electric Service Providers), the provisions of this section shall control.

(k) **Good cause.** Upon a finding of good cause, as determined by the commission, the sequence for retail competition set forth in subsection (e) of this section may be modified by commission order.

§25.431. Retail Competition Pilot Projects.

(a) **Purpose.** This section establishes the parameters under which an electric utility shall offer customer choice for 5.0% of the load in its Texas service area beginning on June 1, 2001, through the implementation of retail competition pilot projects. The commission may use these pilot projects to evaluate the ability of each power region to implement full customer choice on January 1, 2002, including the operational readiness of support systems. The pilot projects conducted under this section also will serve to encourage participation in a competitive retail market and to inform customers about customer choice.

(b) **Application.**

(1) This section applies to an electric utility as defined in the Public Utility Regulatory Act (PURA) §31.002(6). An electric utility exempt from PURA Chapter 39 in accordance with PURA §39.102(c) may conduct a customer choice pilot project consistent with the requirements of this section upon expiration of its exemption. A pilot project commencing before the adoption of this section may fulfill portions of the requirements of this section, as determined by the commission.

(2) Other entities, including retail electric providers (REPs) certified by the commission, and aggregators, power generation companies, and power marketers registered with the commission may participate in the pilot projects under the terms and conditions established by this section.

(c) **Intent of pilot projects.** Pilot projects conducted under this section are intended to implement customer choice for all applicable customers in the same manner in which full customer choice will be offered starting January 1, 2002, to the extent practicable. Unless determined otherwise through a subsequent commission proceeding, or unless stated otherwise in this section, all pilot project participants who are not retail customers shall abide by all applicable commission rules, including but not limited to, rules relating to customer protection and transmission and distribution terms and conditions, and all rules of an independent organization as defined in PURA §39.151.

(1) **Utility's obligation to serve.** A utility shall continue to provide electric service in accordance with PURA and the commission's substantive rules to requesting customers in its certificated service area who do not wish to take service from a REP.

(2) **Indemnification.** Market participants, including utilities, shall be held harmless for any damages resulting from any non-willful system or process failures during the pilot project.

(3) **Performance standards.**

(A) Call center performance may be compromised by potential large increases of customer inquiries generated because of the customer education program and pilot project activities. For the period February 1, 2001 through December 31, 2001, as applicable to each utility,

(i) a reduction of five percentage points will be applied to the percentage of calls to be answered in the allowable time; or

(ii) 5.0% of the calls with the longest wait time will be subtracted from the calculation of average answer time.

(B) An affected utility shall track and report such performance during the pilot project in accordance with applicable commission rules and orders. An affected utility does not waive any rights to request an adjustment or waiver of performance standards directly affected by the customer education program or pilot project.

(4) **Effect of pre-existing service agreements or contracts.**

(A) To the extent a customer is otherwise eligible to participate in a pilot project in accordance with this section, a utility shall not challenge a customer's right to participate:

(i) based upon a claimed failure to provide notice of cancellation in accordance with the requirements of an existing service agreement, contract, or tariff; or

(ii) in the event that the customer's service agreement or contract is beyond its primary term.

(B) To the extent a customer is otherwise eligible to participate in a pilot project in accordance with this section, customers in the primary term of a service agreement or contract shall have the right to participate in the pilot project subject to a challenge by the utility based upon a service agreement or contractual issue other than failure to provide notice of cancellation in compliance with an existing service agreement, contract, or tariff. The procedure for any such challenge shall be as follows:

(i) A utility contending that a customer that has been otherwise selected to participate in the pilot project is not eligible to participate, because of an existing service agreement or contract in its primary term, shall inform the customer not later than seven days after the date scheduled for the lottery for the applicable class in the event the class is oversubscribed or the date the customer requests participation in the event the class is undersubscribed.

(ii) If the customer wishes to dispute the utility's contention, the customer must, within seven days of receipt of the utility's notification, so inform the utility. Pending resolution of the dispute, the utility shall reserve a place for that customer on the participant list.

(iii) The customer shall be entitled to participate in the pilot project unless the utility informs the commission of the pilot project eligibility dispute within seven days of receipt of the customer's notification to the utility disputing the claim of ineligibility. Upon receipt by the commission of timely notice of the dispute, the commission will resolve the dispute within 30 days after filing, and may do so administratively.

(iv) If the commission determines that the customer is eligible to participate, the customer will be included within the pilot project as soon as practicable after the decision.

(5) **Right to withdraw from pilot project.** For any reason, and at a customer's request, the REP and the incumbent utility shall restore a residential customer's account to pre-pilot project services and rates. In the event a customer's REP ceases to do business in Texas during the pilot project, the incumbent utility shall restore any customer's account to pre-pilot project services and rates at the customer's request.

(6) **Application of renewable energy rule.** To encourage access to energy generated from renewable resources by customers participating in the pilot projects, the renewable energy mandate provisions of §25.173 of this title (relating to Goal for Renewable Energy) will be extended on a voluntary basis during the pilot projects to the competitive portion of the market, with the following changes:

(A) Each REP may acquire and retire renewable energy credits (RECs) consistent with its share of retail kilowatt-hour sales during the pilot period (June 1, 2001 through December 31, 2001), at a rate consistent with REC obligations for the year 2002, and in the manner specified in §25.173(h) of this title;

(B) Each REC retired for the pilot period will reduce the REC obligations of the REP for the year 2002 compliance period;

(C) The voluntary settlement period for the pilot project renewable energy program will commence January 1, 2002 and end March 31, 2002; and

(D) Penalty provisions of §25.173(o) of this title are not applicable.

(7) **End of pilot projects.** The pilot projects will end on December 31, 2001, unless determined otherwise by the commission in accordance with subsection (j) of this section. For an electric utility exempt from PURA Chapter 39 in accordance with PURA §39.102(c), the pilot project, if undertaken, will begin and end on dates deemed reasonable by the commission. A customer will remain with the REP by which he or she was served on the last day of the pilot project until the customer or the REP elects otherwise. By participating in the pilot project, a customer does not waive any right to take service under the price to beat in accordance with PURA §39.202.

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

(1) **Aggregation** -- includes the purchase of electricity from a retail electric provider, a municipally owned utility, or an electric cooperative by an electricity customer for its own use in multiple locations or as part of a voluntary association of electricity customers. An electricity customer may not avoid any non-bypassable charges or fees as a result of aggregating its load.

(2) **Customer class** -- a grouping of customers, specific to the pilot projects, for the purpose of allocating loads available for customer choice during the pilot projects. The five customer classes used in the pilot projects are:

(A) **Residential** -- all customers identified by an electric service identifier (ESI) who purchase electricity under a utility's residential rate schedule.

(B) **Non-residential, non-demand metered** -- all customers identified by an ESI who:

(i) do not purchase electricity under a utility's residential rate schedule; and

(ii) do not purchase electricity under a utility's municipal or school rate schedule; and

(iii) do not purchase electricity under a utility's rate schedule that is based on metered or estimated demand during the twelve month period ending December 31, 2000.

(C) **Industrial demand-metered** -- all customers identified by an ESI who:

(i) do not purchase electricity under a utility's residential rate schedule; and

(ii) purchase electricity under a utility's rate schedule that is based on a metered demand; and

(iii) purchase electricity under a utility's industrial rate schedules (or are identified as industrial by the utility's rate code if the utility does not have industrial rate schedules) or have filed a manufacturing or processing tax exemption certificate with the utility.

(D) **Commercial and all other demand-metered** -- all customers identified by an ESI who:

(i) do not purchase electricity under a utility's residential rate schedule; and

(ii) do not come within the definition of the industrial demand metered customer class; and

(iii) purchase electricity under a utility's rate schedule that is based on a metered demand.

(E) **Other** -- The other customer class is composed of all customers identified by an ESI who:

(i) purchase electricity under a utility's rate schedule that is based on known usage patterns, not actual metered data (i.e., unmetered loads); or

(ii) purchase electricity under a utility's municipal or school rate schedules; or

(iii) purchase electricity under utility rate schedules applicable to seasonal agricultural use, such as cotton gins, irrigation, or grain elevators.

(3) **Electric service identifier (ESI)** -- premise-based identifier assigned to each electric service delivery point between a transmission and distribution utility and an end-use load, which is used in the Texas customer registration system and the Electric Reliability Council of Texas (ERCOT) settlement system.

(4) **Lottery** -- fair process in which ESIs or aggregator packets of ESIs are selected for participation in a pilot project by using standard statistical methods for simple random sampling; each ESI or aggregator packet of ESIs should have an equal chance of actually being selected.

(5) **Participation** -- occurs when the customer takes service from a retail electric provider that is not the incumbent, integrated utility.

(e) **Requirements for participants that are not retail customers.**

(1) A REP must be certified by the commission pursuant to §25.107 of this title (relating to Certification of Retail Electric Providers) prior to participating in pilot projects established

pursuant to this section. An affiliated REP shall not participate in the certificated service area of the electric utility with which it is affiliated.

(2) An aggregator, other than a self-aggregator, must be registered with the commission pursuant to §25.111 of this title (relating to Registration of Aggregators) prior to participating in pilot projects established pursuant to this section.

(3) A power generation company must be registered with the commission pursuant to §25.109 of this title (relating to Registration of Power Generation Companies) prior to participating in pilot projects established pursuant to this section. A utility need not be registered as a power generation company in order to generate power for sale during the pilot projects.

(4) A power marketer must be registered with the commission pursuant to §25.105 of this title (relating to Registration and Reporting by Power Marketers) prior to participating in pilot projects established pursuant to this section.

(5) An independent transmission organization outside of ERCOT may require a market participant to register with that organization in order to become a wholesale buyer and seller of energy across the transmission system.

(f) **Customer education.** Customer education for the pilot projects shall be conducted as part of the statewide customer education campaign for introducing customer choice. Included in this campaign will be announcements regarding the opportunity to participate in the pilot project and instructions on obtaining further information about the pilot project. The commission shall mail information written in English and in Spanish explaining the pilot project to eligible non-residential customers no later than March 1, 2001, and to eligible residential customers no later than April 15, 2001. The utility shall provide the commission or its designee with customer information necessary to implement this subsection. For purposes of this subsection, §25.272(g)(1) of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates) does not apply with regard to proprietary customer information released to the commission or its designee. The mailing may contain information including, but not limited to:

(1) a description of the pilot project;

(2) the commission's central call center phone number and Internet website operating to respond to customer questions and requests for information;

(3) a list of REPs certified as of a date certain, including the telephone number and, if available, Internet website address for each REP, and a statement disclosing that the REP list is continually updated and how the customer can obtain an updated list; and

(4) a clear, plain language description of customer choice and the price to beat.

(g) **Customer choice during pilot projects.** The following procedures shall be used for customers to participate in the pilot projects within the designated time periods for each applicable customer class.

(1) **Administration.** For all customer classes, a REP shall submit requests to switch customers participating in the pilot projects to the registration agent beginning on May 31, 2001, and power delivery in conjunction with the pilot projects may begin on June 1, 2001. For purposes of this section, any electronic submission to the utility shall be executed using a standard electronic data interface (EDI) protocol (814) to be included in the utility's compliance filing.

(A) Except where explicitly stated otherwise in this section, a REP shall electronically submit switch requests to the utility for counting and validation purposes prior to submitting such requests to the registration agent. The utility shall maintain a weekly updated list of non-matching, rejected ESIs on its pilot project Internet website.

(B) Except for the industrial demand-metered class, there shall be no out-of-cycle meter reading requests submitted for purposes of the pilot project before July 1, 2001.

(C) Members of the non-residential customer classes may elect to waive the verification and recision process of the registration agent.

(D) A participating customer shall have the right to change from one REP to another REP in accordance with the switching procedures adopted by the commission.

(E) Beginning April 16, 2001, a REP shall electronically report to the utility any switch request for a customer or an aggregation packet with a listing of the ESIs to be switched to the REP as set forth in this paragraph. After the utility confirms that a non-residential ESI or aggregation packet is on the associated participant list, the utility shall submit the ESI to the registration agent. The registration agent shall keep a record of all the ESIs identified by the utility for participation in the pilot. The REP shall be responsible for submitting to the registration agent the ESIs associated with the switch request to serve. If the ESI identified by the REP matches an ESI identified by the utility, then the registration agent shall allow the registration process to continue.

(F) Because the utility is assigned the responsibility to administer the pilot project, except for complaints arising under §25.272 of this title, which may be made in accordance with procedures established under that section, a claim by any party of unreasonableness associated with the administration of the pilot project will first be addressed by the pilot implementation working group established by subsection (j)(4) of this section. If the complaint is not resolved within ten working days of initial notification to the pilot implementation working group, the complaint may be filed with the commission.

(2) **Residential customer class.**

(A) Determination of the 5.0% load available for customer choice. For residential customers, the load available for customer choice shall be determined by calculating 5.0% of the number of ESIs in this customer class as of December 31, 2000. No later than January 31, 2001, the utility shall determine the amount of load available for this customer class and shall make that information publicly available through its pilot project Internet website. For this customer class, 20% of the 5.0% load available for customer choice shall be initially set aside for each customer class (hereafter referred to as the 1.0% set-aside) for aggregated loads.

(B) Initiating switching. Beginning February 15, 2001, a REP may accept authorizations to switch providers from residential customers. A REP shall notify the utility of such authorizations for residential customers.

(C) Reaching the 5.0% load limit. For purposes of this subparagraph the total number of ESIs eligible to switch determined in subparagraph (A) of this paragraph, less the number of ESIs that have already authorized a switch, shall be referred to as the amount of available load.

(i) As each customer in this class authorizes a switch to another provider, the amount of available load shall be decremented by one.

(ii) When the amount of available load reaches zero, no more switch authorizations shall be accepted.

(3) **Non-residential customer classes.**

(A) Determination of the 5.0% load available for customer choice. No later than January 31, 2001, the utility shall make the results of the following calculations for each non-residential customer class publicly available through its pilot project Internet website. For each non-residential customer class, 20% of the 5.0% load available for customer choice shall be initially set aside for each customer class (hereafter referred to as the 1.0% set-aside) for aggregated loads.

(i) Non-residential, non-demand metered customers. For non-residential, non-demand metered customers, the load available for customer choice shall be determined by calculating 5.0% of the number of ESIs in that customer class as of December 31, 2000.

(ii) Industrial demand-metered customers; commercial and all other demand-metered customers. For each of the demand metered customer classes, the load available for customer choice shall be determined by calculating 5.0% of the sum of the kilowatts invoiced by the utility to all ESIs in each customer class for meter reading dates during the utility's peak demand month in the year 2000. In addition, the utility shall determine the individual ESI load caps for each demand metered customer class by calculating 20% of the load available for the pilot project in each demand-metered customer class.

(iii) Other customers as defined in subsection (d)(2)(E) of this section. For all other customers, the load available for customer choice shall be determined by calculating 5.0% of the sum of the kilowatt-hours for which all ESIs in this customer class were invoiced by the utility during the twelve month period ending December 31, 2000. In addition, the utility shall determine the individual ESI load caps for this customer class by calculating 20% of the kilowatt-hours available for the pilot project in this customer class.

(B) Amount of available load. For purposes of this paragraph, the total load available for customer choice determined in subparagraph (A) of this paragraph, less the amount of the customer's ESI load used for calculation in subparagraph (A) of this paragraph, shall be referred to as the amount of available load for each non-residential customer class. For an ESI that was not included in the calculation in subparagraph (A) of this paragraph, hereinafter called a new ESI, the customer's ESI load shall be determined as follows:

(i) For the non-residential, non-demand metered class, a new ESI shall count as one ESI against the total number of ESIs.

(ii) For the demand-metered classes, the demand allocated to a new ESI shall be 95% of the utility-estimated demand for the new ESI.

(iii) For the other class as defined in subsection (d)(2)(E) of this section, the energy allocated to a new ESI shall be 95% of the utility-estimated annual kilowatt-hours for the new ESI.

(C) Open interest period. Beginning February 15, 2001, and continuing through March 15, 2001, interested customers may request the opportunity to participate in a utility's pilot project by submitting to the utility through its pilot project Internet website the account number and zip code information necessary to determine the customer's ESI. An eligible ESI is one that does not exceed the individual ESI load cap established in subparagraph (A) of this paragraph. By March 21, 2001, the utility shall determine if the non-residential customer classes are either oversubscribed or undersubscribed, including the amount of load oversubscribed or undersubscribed, and shall make such information publicly available through its pilot project Internet website.

(i) Participant list. The utility shall create a list of customers eligible to participate in the pilot project, referred to as the participant list. The participant list shall include each ESI and related service address, the name in which the customer is billed, and customer class as defined in this section. No later than March 21, 2001, the utility shall make available its integrated voice response (IVR) system or its pilot project Internet website to allow a customer having an ESI in the lottery to determine whether its ESI has been selected for the participant list. The participant list for each customer class shall be provided to the commission no later than March 21, 2001.

(ii) Oversubscription. On March 21, 2001, if a non-residential customer class is oversubscribed, the utility shall use a lottery to develop the participant list. As each ESI is selected through the lottery, the ESI's load used for the calculation in subparagraph (A) of this paragraph shall be subtracted from the total amount of load available for customer choice as determined in subparagraph (A) of this paragraph. The ESI that causes the 4.0% load limit (i.e., the 5.0% load limit less the 1.0% set-aside) to be reached shall be the final ESI selected through the lottery; the 4.0% limit may be exceeded only for the purpose of accommodating the entire load associated with the final ESI selected, except that such excess shall not cause the amount of load available for customer choice to be greater than 4.1%. Once the 4.0% load limit is reached, the selected ESIs shall be included on the participant list.

(iii) Undersubscription. If a non-residential customer class is undersubscribed, all eligible ESIs submitted shall be included on the participant list. Beginning March 21, 2001, any unsubscribed load will be available for subscription by customers in that customer class on a first come, first served basis.

(D) Negotiation period. Between March 21, 2001 and May 10, 2001, customers on the participant list may negotiate and contract with REPs. A REP shall notify the utility of execution of a contract. If a customer has not entered into a confirmed REP contract for a specific ESI by May 10, 2001, that ESI shall be removed from the participant list, and the load associated with that ESI shall be added to the amount of available load. On May 11, 2001, the utility shall post, on its pilot project Internet website, a list of submitted ESIs that do not match a customer on the participant list. REPs shall have until May 14, 2001 to correct any ESI listed by the utility on May 11, 2001. On May 17, 2001, the utility shall determine the amount of available load for each non-residential customer class and shall make such determination publicly available through its pilot project Internet website.

(E) Monitoring and adjusting the amount of available load. Following the negotiation period, participation shall be allowed on a first come, first served basis.

(i) As each non-residential customer in a class executes a contract, the amount of available load for that class shall be decremented by the amount of the customer's ESI load used for the calculation in subparagraph (A) of this paragraph.

(ii) The ESI that causes the amount of available load to reach zero shall be the final ESI selected; the amount of available load may drop below zero only for the purpose of accommodating the entire load associated with the final ESI selected, subject to the limitations described in subparagraph (C)(ii) of this paragraph.

(4) **Aggregated load set-aside**. Customers participating in customer choice may use aggregation to the extent they choose, and may participate by self aggregation or multiple customer aggregation. For purposes of pilot project administration, aggregators must submit to the utility their groupings of utility account numbers and associated zip codes, or ESIs if available, for participation in the pilot project subject to the 1.0% set-aside. Such groupings (hereafter referred to as aggregation packets) shall be submitted by customer class as defined in subsection (d) of this section with a listing of utility account numbers and associated zip codes.

(A) Set-aside cap. No single aggregation packet may contain an ESI or ESIs that represent more than 20% of the 1.0% set-aside for that customer class, with the exception of the residential class.

(B) Registration dates. Aggregators may register non-residential customer class aggregation packets, subject to the limitation in subparagraph (A) of this paragraph, with the utility beginning February 15, 2001. Aggregators may register residential aggregation packets beginning March 1, 2001.

(C) Undersubscription for all non-residential customer classes. If an aggregation packet contains non-residential ESIs from a class that is undersubscribed as of April 2, 2001, then that aggregation packet shall have a reserved allotment of the 1.0% set-aside until May 21, 2001. If by May 31, 2001, the 1.0% set-aside for aggregation in any non-residential class is undersubscribed, then the utility shall determine the unused class capacity and add it to the amount of available load for that class. No later than June 10, 2001, the utility shall make the updated amount of available load publicly available through the utility's pilot project Internet website.

(D) Aggregation selection process for customer classes. The eligibility for the 1.0% set-aside for each customer class shall be determined as follows:

(i) Residential customer class. Beginning on March 1, 2001, an aggregator may accept authorizations from residential customers to switch providers as a part of an aggregation packet. Aggregators shall submit aggregated utility account numbers and associated service address zip codes to the utility for tracking the 1.0% set-aside on a first come, first served basis. Aggregation packets shall be accepted until either the 1.0% set-aside is reached or June 15, 2001, whichever comes first. If the 1.0% set-aside is not fully subscribed by June 15, 2001, the utility shall determine the unused class capacity and add that unused capacity to the total amount of available load for the residential class.

(ii) Non-residential customer classes. The initial set-aside for each of the non-residential customer classes shall be 1.0% of the eligible load by customer class. To be eligible for the aggregation participant list, an aggregator must provide utility account number and service address zip code information, or ESIs if available, to the utility by April 2, 2001.

(I) Oversubscription for the non-residential, non-demand metered customer class. If the total number of ESIs in aggregation packets submitted for the pilot for a non-residential, non-demand class as of April 2, 2001 exceeds the 1.0% set-aside, then the utility shall use a lottery to determine the aggregation participant list for this class. Aggregation packets eligible for the aggregation participant list shall be selected by the utility by April 5, 2001. As each aggregation packet is selected through the lottery, the ESI count shall be subtracted from the total number of ESI available for the 1.0% set-aside. Aggregation packets shall be selected until none of the 1.0% set-aside is left. If the last aggregation packet selected causes the 1.0% set-aside to be exceeded, the selection of the final aggregation packet for this class shall be done in accordance with subparagraph (E) of this paragraph. By April 6, 2001, the utility shall determine whether an aggregation packet has been selected, and shall make such information publicly available through its pilot project Internet website.

(II) Oversubscription for the industrial demand-metered and commercial and all other demand-metered classes. If the total combined load of all aggregation packets submitted for each of the industrial demand-metered and commercial and all other demand-metered classes exceeds the 1.0% set-aside as of April 2, 2001, then the utility shall use a lottery to determine the aggregation participant list for each customer class. Aggregation packets eligible for the aggregation participant list shall be selected by the utility by April 5, 2001. As an aggregation packet is selected through the lottery, the demand for that ESI used to determine the available capacity for that customer class shall be subtracted from the total demand amount available for the 1.0% set-aside. Aggregation packets shall be selected until none of the 1.0% set-aside is left. If the last aggregation packet selected causes the 1.0% set-aside to be exceeded, the selection of the final aggregation packet for the class shall be done in accordance with subparagraph (E) of this paragraph. No later than April 6, 2001, the utility shall make the list of ESIs eligible for the pilot project publicly available through its pilot project Internet website.

(III) Oversubscription for the other customer class as defined in subsection (d)(2)(e) of this section. If the total combined load of all aggregation packets submitted for the other class exceeds the 1.0% set-aside as of

April 2, 2001, then the utility shall use a lottery to determine the aggregation participant list for this class. Aggregation packets eligible for the aggregation participant list shall be selected by the utility by April 5, 2001. As each aggregation packet is selected through the lottery, the energy in kilowatt-hours for that ESI used to determine the size of the customer class shall be subtracted from the total amount of energy available for the 1.0% set-aside. Aggregation packets shall be selected until none of the 1.0% set-aside is left. If the last aggregation packet selected causes the 1.0% set-aside to be exceeded, the selection of the final aggregation packet for the class shall be done in accordance with subparagraph (E) of this paragraph. No later than April 6, 2001, the utility shall make the list of ESIs eligible for the pilot project for the class publicly available through its pilot project Internet website.

(E) Non-residential customer classes oversubscription lottery selection of last aggregation packet. If the final aggregation packet chosen in a customer class lottery causes the 1.0% set-aside for that customer class to be exceeded by more than 10%, that is, if that aggregation packet increases the size of the customer class to greater than 1.1%, that aggregation packet shall be rejected and another aggregation packet shall be chosen if available. If no other aggregation packet is available to fill each non-residential customer class without exceeding the 10% overage limit, that remaining increment of capacity set-aside will not be subscribed, but will be added to the amount of available capacity for aggregation for that non-residential customer class and will be available on a first come, first served basis. An aggregation packet that does not exceed the 10% overage limit will be allowed. When the results of the oversubscription lottery are posted by the utility, the utility shall also make publicly available the information concerning this available capacity through its pilot project Internet website.

(F) Contract notification due date for non-residential customer classes. By May 21, 2001, a REP must submit verification of executed supply contracts with ESIs and associated zip code to the utility. Any ESI that has not been validated by a REP by this date will relinquish its reserved allotment on the aggregation participant list. The relinquished allotment will then be available for aggregation in that customer class on a first come, first served basis.

(G) Notification of executed contract for non-residential customer classes. The REP shall document the existence of an executed contract for service by electronically submitting a list of ESIs representing executed contracts to the utility. The utility may rely on receipt of this list as proof of the existence of an executed contract. The REP shall file a signed affidavit with the commission attesting to the accuracy of the ESIs on the list.

(H) Electronic submissions by aggregators. All submittals required by this section by aggregators to a utility shall be made in electronic format using a Microsoft Excel spreadsheet using a spreadsheet template posted on the utility's pilot project Internet website. A utility will post its templates by January 31, 2001.

(I) New ESIs. For an ESI that was not included in the calculation in paragraph (3)(A) of this subsection, hereinafter called a new ESI, the customer's ESI load shall be determined as follows:

(i) For the non-residential non-demand metered classes, a new ESI shall count as one ESI against the total number of ESIs.

(ii) For the demand-metered classes, the demand allocated to a new ESI shall be 95% of the utility-estimated demand for the new ESI.

(iii) For the other class as defined in subsection (d)(2)(E) of this section, the energy allocated to a new ESI shall be 95% of the utility-estimated annual kilowatt-hours for the new ESI.

(h) **Transmission and distribution rates and tariffs.**

(1) **Utilities within ERCOT.** In connection with a utility's pilot project, the utility shall provide transmission service and distribution service in accordance with the rates for non-bypassable delivery charges approved by the commission, on an interim basis for application during the utility's pilot project, in the utility's unbundled cost of service case filed pursuant to PURA §39.201. Notwithstanding the provisions of §22.125 of this title (relating to Interim Relief), such interim rates shall not be subject to surcharge or refund if the rates ultimately established differ from the interim rates.

(2) **Utilities outside of ERCOT.**

(A) Jurisdiction of other regulatory bodies. Processes utilized by non-ERCOT participants shall support the settlement of traditional wholesale markets and shall conform to all Federal Energy Regulatory Commission (FERC) rules and regulations.

(B) Transmission service. In connection with a utility's pilot project, the utility shall provide transmission service in accordance with the rates and delivery charges approved by the FERC. A utility in transition to an independent transmission company (ITC) model shall maintain on file with the commission a copy of its current FERC-approved open access transmission tariff (OATT), as well as any proposed amendments to the OATT submitted to FERC.

(C) Distribution service. In connection with a utility's pilot project, the utility shall provide distribution service in accordance with the rates for non-bypassable delivery charges approved by the commission, on an interim basis for application during the utility's pilot project, in the utility's unbundled cost of service case filed pursuant to PURA §39.201. Notwithstanding the provisions of §22.125 of this title, such interim rates shall not be subject to surcharge or refund if the rates ultimately established differ from the interim rates.

(3) **Approval of tariffs.** Tariffs implementing pilot project rates must be filed within ten days following the commission's determination of those rates. The commission shall approve such tariffs by May 31, 2001, and may do so administratively.

(i) **Billing requirements.**

(1) A utility shall bill a customer's REP for non-bypassable delivery charges in accordance with the tariffs established pursuant to subsection (h) of this section. The REP must pay these charges.

(2) A REP shall be responsible for ensuring that its retail customers are billed for electric service provided. A utility may bill retail customers at the request of a REP, provided that any such billing service shall be offered by the utility on comparable terms and conditions for any requesting REP.

(j) **Evaluation of the pilot projects by the commission; reporting.** The commission shall evaluate the pilot projects and the operational readiness of each power region, including its support systems, for customer choice.

(1) **Evaluation criteria.**

(A) Criteria for determining the readiness of a power region for customer choice may include the following:

(i) whether a power region's operational support systems were tested, and any problems that surfaced during the pilot project were adequately rectified;

(ii) whether electric system reliability was significantly affected in an adverse way; and

(iii) any other criteria the commission determines appropriate.

(B) Criteria for determining whether commission rules may need modifications or whether certain aspects of retail competition may require more detailed monitoring by the commission may include the following:

(i) whether participants in the pilot projects represented a broad base of customers of diverse demographic characteristics;

(ii) whether customers were aware of their rights and responsibilities with respect to customer choice, and whether such awareness increased for customers as a whole over the duration of the pilot projects;

(iii) whether a broad range of electric services and products were offered;

(iv) whether the quality of customer service with respect to retail customers was affected; and

(v) any other criteria the commission determines appropriate.

(2) **Information used for evaluation of pilot projects.** Evaluation of the pilot projects shall be based on information including, but not limited to:

(A) reports filed in accordance with paragraph (3) of this subsection;

(B) surveys of retail customers conducted in connection with the commission's customer education program; and

(C) the quantity and nature of complaints or inquiries regarding the pilot project received by the commission's Office of Customer Protection.

(3) **Reporting by market participants and independent organizations.** Each market participant and independent organization shall file two status reports with the commission under a single project number as designated by the commission's central records division. The first status report shall be filed on November 15, 2001, and the second no later than 30 days following the conclusion of the pilot project. In addition, a utility subject to PURA Chapter 39, Subchapter I, shall file semi-annual reports with the commission for the duration of its pilot project to permit the commission to monitor whether proportional representation is achieved in accordance with subsection (l)(3)(B) of this section.

(A) Reporting by utilities. Each status report from a utility shall include:

(i) The percent of load switched by month and cumulatively, for each customer class as defined in this section, including supporting data;

(ii) The number of customers that have withdrawn from the pilot project, by customer class;

(iii) A summary of any technical problems encountered during the reporting period, including resolutions or proposed resolutions, as appropriate, and supporting data;

(iv) A summary of all complaints related to the pilot project received by the utility during the reporting period, including a description of the resolution of the complaints;

(v) For a utility in transition to an ITC model, a progress report on the transition to the ITC, including any updates to the initial compliance filing; and

(vi) Any other information the utility believes will assist the commission in evaluating the pilot projects and the readiness of a power region for implementation of full customer choice.

(B) Reporting by REPs. Each status report from a REP shall include:

(i) A summary of any technical problems encountered during the reporting period, including resolutions or proposed resolutions, as appropriate, and supporting data;

(ii) A summary of all complaints related to the pilot project received by the REP during the reporting period, including a description of the resolution of the complaints; and

(iii) Any other information the REP believes will assist the commission in evaluating the pilot projects and the readiness of a power region for implementation of full customer choice.

(C) Reporting by an independent organization. Each status report from an independent organization shall include:

(i) Data from the registration agent regarding the average time elapsed between a switch request and the time the switch became effective;

(ii) Data from the registration agent, categorized by residential and non-residential customers, listing the total number of switch requests for each month, as well as the average number of switch requests per day for each month, and the total number of switch requests by zip code;

(iii) Data from the registration agent regarding the number of rejected switch requests resulting from the anti-slamming verification process;

(iv) A summary of all complaints, categorized by REP and by utility, related to the pilot project captured in the registration agent's systems during the reporting period, including a description of the resolution of the complaints;

(v) A summary from the registration agent and the independent organization, as applicable, of any technical problems encountered during the reporting period, including resolutions or proposed resolutions, as appropriate, and supporting data; and

(vi) An analysis by the independent transmission organization of system reliability during the pilot projects.

(D) Other reporting.
At any time, a pilot project participant who is neither a utility nor a REP may provide the commission with any information the participant believes will assist the commission in evaluating the pilot projects and the readiness of a power region for implementation of full customer choice.

(4) **Pilot implementation working group.** The commission will establish a pilot implementation working group to oversee the pilot projects. The commission or its designee, based upon a recommendation of the pilot implementation working group, may revise the operational requirements of the pilot projects in order to resolve technical problems encountered by market participants.

(5) **Extension of pilot projects.** Should the commission determine that it is necessary to delay competition and extend the pilot projects, it must make such determination by December 31, 2001, except as otherwise authorized by PURA §39.405.

(k) **Pilot project administration and recovery of associated costs.**

(1) Each utility shall be responsible for administering the pilot project for its service area. Costs incurred by the utility to administer the pilot project may include expenses for required communications, third-party outsourcing for any or all administration tasks, enrollment process, or lottery administration.

(2) The utility may request recovery from the commission of pilot project administrative costs through:

(A) inclusion in the annual report filed pursuant to PURA §39.257; or

(B) deferral to future retail transmission or distribution rates.

(3) Parties do not waive the right to challenge the utility's ability to seek cost recovery for costs associated with the pilot projects at the time that such relief is sought. In addition, nothing in this section shall be construed as resolving the legal issue of whether utilities may recover costs associated with the pilot projects.

(l) **Compliance filings**.

(1) **Timing and review.** Each utility shall file a pilot project implementation plan with the commission under a project number designated by the commission's central records division. An

implementation plan filed under this section shall be reviewed administratively to determine whether it is consistent with the principles, instructions and requirements set forth in this section.

(A) Each utility shall file its implementation plan within 45 days of the commission's adoption of this section. Such filings do not constitute contested case proceedings, but are designed to describe the particular application of this section to the filing utility for the purpose of providing information to the public and the commission.

(B) No later than 15 days after filing, interested parties may file comments on the implementation plan.

(C) No later than 25 days after filing, commission staff may file a recommendation concerning the implementation plan.

(D) Unless the commission or presiding officer determines otherwise, an implementation plan filed under this section shall be deemed approved on the thirtieth day after filing. If the implementation plan is not approved, the utility shall resubmit its plan following consultation with commission staff under a deadline established by the presiding officer.

(2) **Content.** The compliance filing shall address each provision of this section with a brief narrative explaining how the utility intends to implement that provision, including the utility's pilot project Internet website address and other contact information, as applicable. Numerical and formulaic data shall also be provided where applicable. Specifically, the compliance filing shall detail the calculation of the 5.0% load available for each customer class, including the 1.0% set-aside, and demonstrate the calculation with sample data. The final calculations containing actual data shall be filed with the commission by January 31, 2001.

(3) **Additional requirements for non-ERCOT utilities.**

(A) A utility subject to PURA Chapter 39, Subchapter I, shall include in its transition plan filed pursuant to PURA §39.402, a plan for extending its pilot project beyond January 1, 2002. The plan for extension of the pilot project shall contain:

(i) The utility's proposed increase(s) in pilot project participation beyond 5.0%, and proposed timing for such increase(s), including supporting data and workpapers; and

(ii) A report to the commission on market conditions in the utility's power region, including an analysis of the level of competition that the region can support and all relevant data and workpapers.

(B) A utility subject to PURA Chapter 39, Subchapter I, shall include in its compliance filing, a plan to ensure proportional representation in its pilot project between customers receiving service from the utility in an area that is certificated solely to the utility and those customers of the utility located in multiply certificated areas.

(C) A utility in transition to an ITC model shall include in its compliance filing:

(i) a narrative of how its plan for transition to an ITC is expected to affect the pilot project, including relevant supporting data and workpapers; and

(ii) an explanation of any requirements of market participants that are unique to its service area (e.g., registration with ITC, data aggregation requirements).

§25.471. General Provisions of Customer Protection Rules.

(a) **Application.** This subchapter applies to aggregators and retail electric providers (REPs). In addition, where specifically stated, these rules shall apply to transmission and distribution utilities (TDUs), the registration agent and power generation companies. These rules specify when certain provisions are applicable only to some, but not all, of these providers.

(1) Affiliated REP customer protection rules, to the extent the rules differ from those applicable to all REPs or those that apply to the provider of last resort (POLR), do not apply to the affiliated REP when serving customers outside the geographic area served by its affiliated transmission and distribution utility. The affiliated REP customer protection rules apply until the price-to-beat obligation ends in the affiliated REPs' affiliated TDU service territory.

(2) Requirements applicable to a POLR apply to a REP only in its provision of service as a POLR.

(3) The rules in this subchapter are minimum, mandatory requirements that shall be offered to or complied with for all customers unless otherwise specified. Except for the provisions of §25.495 of this title (relating to Unauthorized Change of Retail Electric Provider), §25.481 of this title (relating to Unauthorized Charges), and §25.485(a)-(b) of this title (relating to Customer Access and Complaint Handling), a customer other than a residential or small commercial class customer, or a non-residential customer whose load is part of an aggregation in excess of 50 kilowatts, may agree to terms of service that reflect either a higher or lower level of customer protections than would otherwise apply under these rules. Any agreements containing materially different protections from those specified in these rules shall be reduced to writing and provided to the customer. Additionally, copies of such agreements shall be provided to the commission upon request.

(4) The rules of this subchapter control over any inconsistent provisions, terms, or conditions of a REP's terms of service or other documents describing service offerings for customers in Texas.

(5) For purposes of this subchapter, a municipally owned utility or electric cooperative is subject to the same provisions as a REP where the municipally owned utility or electric cooperative sells retail electricity service outside its certificated service area.

(b) **Purpose.** The purposes of this subchapter are to:

(1) provide minimum standards for customer protection. An aggregator or REP may adopt higher standards for customer protection, provided that the prohibition on discrimination set forth in subsection (c) of this section is not violated;

(2) provide customer protections and disclosures established by other state and federal laws and rules including but not limited to the Fair Credit Reporting Act (15 U.S.C. §1681, et seq.) and the Truth in Lending Act (15 U.S.C. §1601, et seq.). Such protections are applicable where appropriate, whether or not it is explicitly stated in these rules;

(3) provide customers with sufficient information to make informed decisions about electric service in a competitive market; and

(4) prohibit fraudulent, unfair, misleading, deceptive, or anticompetitive acts and practices by aggregators and REPs in the marketing, solicitation and sale of electric service and in the administration of any terms of service for electric service.

(c) **Prohibition against discrimination.** This subchapter prohibits REPs from unduly refusing to provide electric service or otherwise unduly discriminating in the marketing and provision of electric service to any customer because of race, creed, color, national origin, ancestry, sex, marital status, lawful source of income, level of income, disability, familial status, location of customer in an economically distressed geographic area, or qualification for low-income or energy efficiency services.

(d) **Definitions.** For the purposes of this subchapter the following words and terms have the following meaning, unless the context clearly indicates otherwise:

(1) **Applicant--**A person who applies for electric service via a move-in or switch with a REP that is not currently the person's REP of record or applies for aggregation services with an aggregator from whom the person is not currently receiving aggregation services.

(2) **Burned Veteran**--A customer who is a military veteran who a medical doctor certifies has a significantly decreased ability to regulate body temperature because of severe burns received in combat.

(3) **Competitive energy services--**As defined in §25.341 of this title (relating to Definitions).

(4) **Customer--**A person who is currently receiving retail electric service from a REP in the person's own name or the name of the person's spouse, or the name of an authorized representative of a partnership, corporation, or other legal entity, including a person who is changing premises but is not changing their REP.

(5) **Electric service--**Combination of the transmission and distribution service provided by a transmission and distribution utility, municipally owned utility, or electric cooperative, metering service provided by a TDU or a competitive metering provider, and the generation service provided to an end-use customer by a REP. This term does not include optional competitive energy services, as defined in §25.341 of this title, that are not required for the customer to obtain service from a REP.

(6) **Energy service--**As defined in §25.223 of this title (relating to Unbundling of Energy Service).

(7) **Enrollment--**The process of obtaining authorization and verification for a request for service that is a move-in or switch in accordance with this subchapter.

(8) **In writing--**Written words memorialized on paper or sent electronically.

(9) **Move-in--**A request for service to a new premise where a customer of record is initially established or to an existing premise where the customer of record changes.

(10) **Retail electric provider (REP)--**Any entity as defined in §25.5 of this title (relating to Definitions). For purposes of this rule, a municipally owned utility or an electric cooperative is only considered a REP where it sells retail electric power and energy outside its certified service territory. An agent of the REP may perform all or part of the REP's responsibilities pursuant to this subchapter. For purposes of this subchapter, the REP shall be responsible for the actions of the agent.

(11) **Small commercial customer--**A non-residential customer that has a peak demand of less than 50 kilowatts during any 12-month period, unless the customer's load is part of an aggregation program whose peak demand is in excess of 50 kilowatts during the same 12- month period.

(12) **Switch--**The process by which a person changes REPs without changing premises.

(13) **Termination of service--**The cancellation or expiration of a service agreement or contract by a REP or customer.

§25.472. Privacy of Customer Information.

(a) **Mass customer lists.** Prior to the commencement of retail competition, an electric utility shall release a mass customer list to certificated retail electric providers (REPs) and registered aggregators.

(1) A mass customer list shall consist of the name, billing address, rate classification, monthly kilowatt-hour usage for the most recent 12-month period, meter type, and account number or electric service identifier (ESI-ID). All customers eligible for the price to beat pursuant to the Public Utility Regulatory Act (PURA) §39.202 shall be included on the mass customer list, except a customer who opts not to be included on the list pursuant to paragraph (2) of this subsection.

(2) Prior to the release of a mass customer list, an electric utility shall mail a notice to all customers who may be included on the list. The notice shall:

(A) explain the issuance of the mass customer list;

(B) provide the customer with the option of not being included on the list and allow the customer at least 30 days to exercise that option;

(C) inform the customer of the availability of the no call lists pursuant to §25.484 of this title (relating to Texas Electric No-Call List) and §26.37 of this title (relating to Texas No-Call List), and provide the customer with information on how to request placement on the list;

(D) provide a toll free telephone number and an Internet website address to notify the electric utility of the customer's desire to be excluded from the mass customer list.

(3) The commission will require the electric utility to release a mass customer list no later than 120 days before the commencement of customer choice.

(4) The mass customer list shall be issued, at no charge, to all REPs certified by, and aggregators registered with, the commission that will be providing retail electric or aggregation services to residential or small commercial customers.

(5) A REP shall not use the list for any purpose other than marketing electric service and verifying a customer's authorized selection of a REP prior to submission of the customer's enrollment to the registration agent.

(b) **Individual customer and premise information.**

(1) A REP or aggregator shall not release proprietary customer information, as defined in §25.272(c)(5) of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates), to any other person, including an affiliate of the REP, without obtaining the customer's or applicant's verifiable authorization by means of one of the methods authorized in §25.474 of this title (relating to Selection of Retail Electric Provider). This prohibition shall not apply to the release of such information by a REP or aggregator to:

(A) the commission in pursuit of its regulatory oversight or the investigation and resolution of customer complaints involving REPs or aggregators;

(B) an agent, vendor, partner, or affiliate of the REP or aggregator engaged to perform any services for or functions on behalf of the REP or aggregator, including marketing of the REP's or aggregator's own products or services, or products or services offered pursuant to joint agreements between the REP or aggregator and a third party;

(i) All such agents, vendors, partners, or affiliates of the REP or aggregator shall be required to sign a confidentiality agreement with the REP or aggregator and agree to be held to the same confidentiality standards as the REP or aggregator pursuant to this section; and

(ii) In the event that a REP shares proprietary customer information with a third party for the purpose of marketing such party's products or services to the REP's customer, prior to the release of information to any such agent, partner or affiliate, a REP or aggregator shall provide the customer an opportunity to opt-out of the release of their information for such marketing purposes by either of the following methods:

(I) send a notice to customers explaining the issuance of the each information release and the reason for the information release and provide the customer with the option of not being included in the information release and allow the customer at least 30 days to exercise that option; or

(II) include an opportunity for the customer to make a choice as to whether or not the customer wants to be included in all future marketing of other products and services by the REP or its agent, partner, or affiliate. Such opportunity may be provided during the authorization and verification process detailed in §25.474 or via a separate notice and mailing to customers.

(C) a consumer reporting agency as defined by the Federal Trade Commission;

(D) an energy assistance agency to allow a customer or an applicant to qualify for and obtain other financial assistance provided by the agency. A REP may rely on the representations of an entity claiming to provide energy assistance;

(E) local, state, and federal law enforcement agencies;

(F) the transmission and distribution utility (TDU) within whose geographic service territory the customer or applicant is located, pursuant to the provisions of the TDU's commission-approved Tariff for Retail Electric Delivery Service;

(G) the Office of the Public Utility Counsel, upon request pursuant to PURA **§**39.101(d);

(H) conduct activities required by subsection (a) of this section;

(I) the registration agent, another REP, a provider of last resort (POLR), or TDU as necessary to complete a required market transaction, under terms approved by the commission; or

(J) the registration agent or a TDU in order to effectuate a customer's move-in, transfer, or switch.

(2) Under no circumstances shall a REP or aggregator sell, make available for sale, or authorize the sale of any customer-specific information or data obtained.

(3) Upon receiving authorization from a customer or applicant, a REP shall request from the TDU the monthly usage of the customer's or applicant's premise for the previous 12 months. The TDU, upon receipt of a written request or other proof of authorization, shall provide the requested information to the requesting REP or to the customer or applicant no later than three business days after the request or proof of authorization is submitted.

(4) A REP shall, upon the request of an energy assistance agency, provide a 12-month billing history free of charge that includes both usage data and the dollar amount of each monthly billing. If 12 months of billing data are not available from the REP, the REP shall estimate the amount billed using the REP's residential rate. The history shall also clearly designate estimated amounts. A residential billing history requested by an energy assistance agency shall be provided by the end of the next business day after the request is made. A residential billing history requested by a customer shall be provided within five business days of the customer request.

(5) Upon the request of a customer, a REP shall notify a third person chosen by the customer of any pending disconnection of electric service with respect to the customer's account.

§25.473. Non-English Language Requirements.

(a) **Applicability**. This section applies to retail electric providers (REPs), aggregators, and the registration agent.

(b) **Retail electric providers (REPs).** A REP shall provide the following information to an applicant or customer in English, Spanish, or the language used in the marketing of service, as designated by the applicant or customer.

(1) Terms of service documents, Electricity Facts Label, customer bills, and customer bill notices;
(2) information on the availability of new electric services, discount programs, and promotions; and
(3) access to customer service, including the restoration of electric service and response to billing inquiries.

(c) **Aggregators.** An aggregator shall provide the following information to a customer in English, Spanish, or the language used to market the aggregator's products and services, as designated by the customer or the applicant:

(1) terms of service documents required by this subchapter;
(2) the availability of electric discount programs; and
(3) access to customer service.

(d) **Dual language requirement.** The following documents shall be provided to all customers in both English and Spanish, unless a customer has designated a language other than English or Spanish as the language in which they will receive the information described in subsection (b) of this section, in which case the documents described in paragraphs (1) and (3) of this subsection shall be provided in English and the other language designated by the customer.

(1) Your Rights as a Customer disclosure;
(2) the enrollment notification notice provided by the registration agent pursuant to §25.474(l) of this title (relating to Selection of Retail Electric Provider); and
(3) a disconnection notice.

(e) **Prohibition on mixed language.** Unless otherwise noted in this subchapter, if any portion of a printed advertisement, electronic advertising over the Internet, direct marketing material, billing statement, terms of service document, or Your Rights as a Customer disclosure is translated into another language, then all portions shall be translated into that language. A single informational statement advising how to obtain the same printed advertisements, electronic advertising over the Internet, direct marketing material, billing statement, terms of service documents, or Your Rights as a Customer disclosure in a different language is permitted.

§25.474. Selection of Retail Electric Provider.

(a) **Applicability**. This section applies to retail electric providers (REPs) and aggregators seeking to enroll applicants or customers for retail electric service. In addition, where specifically stated, this section applies to transmission and distribution utilities (TDUs) and the registration agent.

(b) **Purpose**. The provisions of this section establish procedures for enrollment of applicants or customers by a REP and ensure that all applicants and customers in this state are protected from an unauthorized switch from the applicant's or customer's REP of choice or an unauthorized move-in. A contested switch in providers shall be presumed to be unauthorized unless the REP provides proof, in accordance with the requirements of this section, of the applicant's or customer's authorization and verification.

(c) **Initial REP selection process**.

(1) In conjunction with the commission's customer education campaign, the commission may issue to customers for whom customer choice will be available an explanation of the REP selection process. The customer education information issued by the commission may include, but is not limited to:

(A) an explanation of retail electric competition;

(B) a list of all REPs certified to provide electric service to the customer;

(C) a form that allows the customer to contact or select one or more of the listed REPs from which the customer desires to receive information or to be contacted; and

(D) information on how a customer may designate whether the customer would like to be placed on the statewide Do Not Call List and indicate the fee for such placement.

(2) Any affiliated REP assigned to serve a customer that is entitled to receive the price-to-beat rate, pursuant to the Public Utility Regulatory Act (PURA) §39.202(a), shall issue to a customer, either as a bill insert or through a separate mailing, no later than 30 days after the commencement of customer choice:

(A) A terms of service document that includes an explanation of the price-to-beat rate;

(B) Your Rights as a Customer disclosure; and

(C) An Electricity Facts Label for the price to beat, which may, at the discretion of the REP, be in a separate document or contained in the terms of service document.

(3) An electric utility whose successor affiliated REP will continue to serve customers not eligible for the price-to-beat rate, pursuant to PURA §39.102(b), shall issue to the customer a terms of service document on a date prescribed by the commission. Such a document shall contain an explanation of the price the customer will be charged by the affiliated REP.

(d) **Enrollment via the Internet.** For enrollments of applicants via the Internet, a REP or aggregator shall obtain authorization and verification of the move-in or switch request from the applicant in accordance with this subsection.

(1) The website (or websites) shall clearly and conspicuously identify the legal name of the aggregator and its registration number to provide aggregation services or REP and its certification number to sell retail electric service, its address, and telephone number.

(2) The website shall include a means of transfer of information, such as electronic enrollment, renewal, and cancellation information between the applicant or customer and the REP or aggregator that is an encrypted transaction using Secure Socket Layer or similar encryption standard to ensure the privacy of customer information.

(3) The website shall include an explanation that a move-in or a switch can only be made by the electric service applicant or the applicant's authorized agent.

(4) The entire enrollment process shall be in plain, easily understood language. The entire enrollment shall be the same language. Nothing in this section is meant to prohibit REPs or aggregators from utilizing multiple enrollment procedures or websites to conduct enrollments in multiple languages.

(5) **Required authorization disclosures.** Prior to requesting confirmation of the move-in or switch request, a REP or aggregator shall clearly and conspicuously disclose the following information:

(A) the name of the new REP;

(B) the name of the specific electric service package or plan for which the applicant's assent is attained;

(C) the ability of an applicant to select to receive information in English, Spanish, or the language used in the marketing of service to the applicant. The REP or aggregator shall provide a means of documenting a customer's language preference;

(D) the price of the product or plan, including the total price stated in cents per kilowatt-hour, for electric service;

(E) term or length of the term of service;

(F) the presence or absence of early termination fees or penalties, and applicable amounts;

(G) any requirement to pay a deposit and the estimated amount of that deposit, or the method in which the deposit will be calculated. An affiliated REP or provider of last resort (POLR) shall also notify the applicant of the right to post a letter of guarantee in lieu of a deposit in accordance with §25.478(i) of this title (relating to Credit Requirements and Deposits);

(H) any fees to the applicant for switching to the REP pursuant to subsection (n) of this section;

(I) in the case of a switch request, the applicant's right, pursuant to subsection (j) of this section, to review and rescind the terms of service within three federal business days, after receiving the terms of service, without penalty;

(J) a statement that the applicant will receive a copy of the terms of service document via email or, upon request, via regular US mail, that will explain all the terms of the agreement and how to exercise the right of rescission, if applicable; and

(K) if the customer is being enrolled for prepaid service as defined by §25.498(b)(7) of this title (relating to Prepaid Service), that the customer will not receive a bill and may request a summary of usage and payment.

(6) The applicant shall be required to check a box affirming that the applicant has read and understands the disclosures and terms of service required by paragraph (5) of this subsection.

(7) The REP or aggregator shall provide access to the complete terms of service document that is being agreed to by the applicant on the website such that the applicant may review the terms of service prior to enrollment. A prompt shall also be provided for the applicant to print or save the terms of service document to which the applicant assents, and shall inform the application of the option to request that a written copy of the terms of service document be sent by regular U.S. mail by contacting the REP.

(8) The REP or aggregator shall also provide a toll-free telephone number, Internet website address, and e-mail address for contacting the REP or aggregator throughout the duration of the applicant's or customer's agreement. The REP or aggregator shall also provide the appropriate toll-free telephone number that the customer can use to report service outages.

(9) Applicant authorizations shall adhere to any state and federal guidelines governing the use of electronic signatures.

(10) **Verification of authorization for Internet enrollment.** Prior to final verification by the applicant of enrollment with the REP or aggregator, the REP or aggregator shall:

(A) obtain or confirm the applicant's email address, billing name, billing address, service address, and name of any authorized representative;

(B) obtain or confirm the applicant's electric service identifier (ESI-ID), if available;

(C) affirmatively inquire whether the applicant has decided to establish new service or change from the current REP to the new REP;

(D) affirmatively inquire whether the applicant designates the new REP to perform the necessary tasks to complete a switch or move in for the applicant's service with the new REP; and

(E) obtain or confirm one of the following account access verification data: last four digits of the social security number, mother's maiden name, city or town of birth, month and day of birth, driver's license or government issued identification number. For non-residential applicants, the REP may obtain the applicant's federal tax identification number.

(11) After enrollment, the REP or aggregator shall send a confirmation, by email, of the applicant's request to select the REP. The confirmation email shall include:

(A) in the case of a switch, a clear and conspicuous notice of the applicant's right, pursuant to subsection (j) of this section, to review and rescind the terms of service within three federal business days, after receiving the terms of service without penalty and offer the applicant the option of exercising this right by toll-free number, email, Internet website, facsimile transmission or regular mail. This notice shall be accessible to the applicant without need to open an attachment or link to any other document; and

(B) the terms of service and Your Rights as a Customer documents. These may be documents attached to the confirmation email, or the REP or aggregator may include a link to an Internet webpage containing the documents.

(e) **Written enrollment.** For enrollments of customers via a written letter of authorization (LOA), a REP or aggregator shall obtain authorization and verification of the switch or move-in request from the applicant in accordance with this subsection.

(1) All LOAs for move-in or switch orders shall be in plain, easily understood language. The entire enrollment shall be in the same language.

(2) The LOA shall be a separate or easily separable document containing the requirements prescribed by this subsection for the sole purpose of authorizing the REP to initiate a switch request. The LOA is not valid unless it is signed and dated by the customer requesting the move-in or switch.

(3) The LOA may contain a description of inducements associated with enrolling with the REP; however, the actual inducement itself shall not be either included on or as part of the LOA, or constitute the LOA by itself.

(4) The LOA shall be legible and shall contain clear and unambiguous language;

(5) **Required authorization disclosures.** The LOA shall disclose the following information:

(A) the name of the new REP;

(B) the name of the specific electric service package or plan for which the applicant's assent is attained;

(C) the ability of an applicant to select to receive information in English, Spanish, or the language used in the marketing of service to the applicant. The REP shall provide a means of documenting an applicant's language preference;

(D) the price of the product or plan, including the total price stated in cents per kilowatt-hour, for electric service;

(E) term or length of the term of service;

(F) the presence or absence of early termination fees or penalties, and applicable amounts;

(G) any requirement to pay a deposit and the estimated amount of that deposit, or the method in which the deposit will be calculated. An affiliated REP or POLR shall also notify the applicant of the right to post a letter of guarantee in lieu of a deposit in accordance with §25.478(i) of this title;

(H) any fees to the applicant for switching to the REP pursuant to subsection (n) of this section;

(I) in the case of a switch, the applicant's right, pursuant to subsection (j) of this section, to review and rescind the terms of service within three federal business days, after receiving the terms of service, without penalty;

(J) a statement that the applicant will receive a written copy of the terms of service document that will explain all the terms of the agreement and how to exercise the right of rescission, if applicable; and

(K) if the customer is being enrolled for prepaid service as defined by §25.498(b)(7) of this title, that the customer will not receive a bill and may request a summary of usage and payment.

(6) **Verification of authorization of written enrollment.** A REP or aggregator shall, as part of the LOA:

(A) obtain or confirm the applicant's billing name, billing address, and service address;

(B) obtain or confirm the applicant's ESI-ID, if available;

(C) affirmatively inquire whether the applicant has decided to establish new service or change from their current REP to the new REP;

(D) affirmatively inquire whether the applicant designates the new REP to perform the necessary tasks to complete a switch or move in for the applicant's service with the new REP; and

(E) obtain one of the following account access verification data: last four digits of the social security number, mother's maiden name, city or town of birth, month and day of birth, driver's license or government issued identification number. For non-residential applicants, the REP may obtain the applicant's federal tax identification number.

(7) The following LOA form meets the requirements of this subsection if modified as appropriate for the requirements of paragraph (5)(G) of this subsection. Other versions may be used, but shall contain all the information and disclosures required by this subsection.

LETTER OF AUTHORIZATION

REP name and license number:____________________________________
Applicant billing name: ____
Applicant billing address: ______________________________________
Applicant service address: ______________________________________
City, state, zip code: ____
ESI ID, if available: ____

If applicable, name of individual legally authorized to act for customer and relationship to applicant:
____
Telephone number of individual authorized to act for applicant: ____________________

____By initialing here, I acknowledge that I have read and understand the terms of service for the product for which I am enrolling.

____By initialing here, I acknowledge that I understand that the price I am agreeing to is ____cents per kWh, the term of service that I am agreeing to is ___________________, that I will be required to pay a deposit in the amount of $_______in order to enroll, that I prefer to receive information from my REP in English/Spanish (circle one), and that there is a penalty for early cancellation of ________as specified by the terms of service.

____By initialing here and signing below, I am authorizing (name of new REP) to become my new retail electric provider and to act as my agent to perform the necessary tasks to establish my electric service account with (name of new REP). This authorization to establish or switch my provider of electric service extends to the following locations (list each service address):
____

____

I have read and understand this Letter of Authorization and the terms of service that describe the service I will be receiving. I am at least eighteen years of age and legally authorized to select or change retail electric providers for the service address(s) listed above.

Signed: ______________________________ Date:_________________

You have the right to review and, in the case of a switch request, rescind the terms of service within three federal business days, after receiving the terms of service, without penalty. You will receive a written copy of the terms of service document that will explain all the terms of the agreement and how to exercise the right of rescission before your electric service is switched to the REP.

(8) Before obtaining a signature from a customer, a REP shall:
   (A) provide to the applicant a reasonable opportunity to read the terms of service, Electricity Facts Label, Prepaid Disclosure Statement (PDS), if applicable, and any written materials accompanying the terms of service document; and
   (B) answer any questions posed by any applicant about information contained in the documents.

(9) Upon obtaining the applicant's signature, a REP or aggregator shall immediately provide the applicant a legible copy of the signed LOA, and shall distribute or mail the terms of service document, Electricity Facts Label, PDS, if applicable, and Your Rights as a Customer disclosure. If a written solicitation by a REP contains the terms of service document, any tear-off portion that is submitted by the applicant to the REP to obtain electric service shall allow the applicant to retain the terms of service document.

(10) The applicant's signature on the LOA shall constitute an authorization of the move-in or switch request if the LOA complies with the provisions of this section and the terms of service comply with the requirements of §25.475(d) of this title (relating to General Retail Electric Provider Requirements and Information Disclosures to Residential and Small Commercial Customers).

(f) **Enrollment via door-to-door sales**. A REP or aggregator that engages in door-to-door marketing at a customer's residence shall comply with the following requirements:

(1) Solicitation requirements. A REP or aggregator that engages in door-to-door marketing at an applicant's residence shall comply with the following requirements:
   (A) The REP or aggregator shall provide the disclosures required by this section and the three-day right of rescission required by the Federal Trade Commission's Trade Regulation Rule Concerning Cooling Off Period for Sales Made at Homes or at Certain Other Locations (16 C.F.R. Part 429).
   (B) The individual who represents the REP or aggregator shall wear a clear and conspicuous identification of the REP or aggregator on the front of the individual's outer clothing or on an identification badge worn by the individual. In addition, the individual shall wear an identification badge that includes the individual's name and photograph, the REP or aggregator's certification or registration number, and a toll-free telephone number maintained by the REP or aggregator that the applicant may call to verify the door-to-door representative's identity during specified business hours. The company name displayed shall conform to the name on the REP's certification or aggregator's registration obtained from the commission and the name that appears on all of the REP's or aggregator's contracts and terms of service documents in possession of the individual.
   (C) The REP or aggregator shall affirmatively state that it is not a representative of the applicant's transmission and distribution utility or any other REP or aggregator. The REP's or aggregator's clothing and sales presentation shall be designed to avoid the

impression by a reasonable person that the individual represents the applicant's transmission and distribution utility or any other REP or aggregator.

(D) The REP or aggregator shall not represent that an applicant or customer is required to switch service in order to continue to receive power.

(E) Door-to-door representatives shall adhere to all local city/subdivision guidelines concerning door-to-door solicitation.

(2) **Required authorization disclosures**. Prior to requesting verification of the applicant's authorization to enroll, a REP or aggregator shall comply with all of the authorization disclosure requirements in either subsections (e)(5) or (h)(1) - (4) of this section.

(3) **Verification of authorization for door-to-door enrollment**. A REP, or an independent third party retained by the REP, shall telephonically obtain and record all required verification information from the applicant to verify the applicant's decision to enroll with the REP in accordance with this paragraph.

(A) Electronically record on audiotape, a wave sound file, or other recording device the entirety of an applicant's verification. The verification call shall comply with the requirements in subsection (h)(5) of this section.

(B) Inform the applicant that the verification of authorization call is being recorded.

(C) Verification shall be conducted in the same language as that used in the sales transaction and authorization.

(D) Automated systems shall provide the applicant with the option of exiting the system and nullifying the enrollment at any time during the call.

(E) A REP or its sales representative initiating a three-way call or a call through an automated verification system shall not participate in the verification process.

(F) The REP shall not submit a move-in or switch request until it has obtained a recorded telephonic verification of the enrollment.

(g) **Personal solicitations other than door-to-door marketing**. A REP or aggregator that engages in personal solicitation at a location other than a customer's residence (such as malls, fairs, or places of business) shall comply with all requirements for written enrollments and LOA requirements detailed in subsection (e) of this section. In addition, the REP or aggregator shall comply with the following additional requirements:

(1) For transactions occurring at a place other than the REP or aggregator's place of business, the REP or aggregator shall provide the three-day right of rescission required by the Federal Trade Commission's Trade Regulation Rule Concerning Cooling-Off Period for Sales Made at Homes or at Certain Other Locations (16 C.F.R. Part 429).

(2) For solicitations of residential customers, the individual who represents the REP or aggregator shall wear a clear and conspicuous identification of the REP or aggregator on the front of the individual's outer clothing or on an identification badge worn by the individual. The company name displayed shall conform to the name on the REP's certification or aggregator's registration obtained from the commission and the name that appears on all of the REP's or aggregator's contracts and terms of service documents in possession of the individual.

(3) The individual who represents the REP or aggregator shall not state or imply that it is a representative of the customer's transmission and distribution utility or any other REP or aggregator. The REP's or aggregator's clothing and sales presentation shall be designed to avoid the impression by a reasonable person that the individual represents the applicant's transmission and distribution utility or any other REP or aggregator.

(4) The REP or aggregator shall not represent that an applicant is required to switch service in order to continue to receive power.

(h) **Telephonic enrollment**. For enrollments of applicants via telephone solicitation, a REP or aggregator shall obtain authorization and verification of the move-in or switch request from the applicant in accordance with this subsection.

(1) A REP or aggregator shall electronically record on audio tape, a wave sound file, or other recording device the entirety of an applicant's authorization and verification. Automated systems shall provide the customers with either the option of speaking to a live person at any time during the call, or the option to exit the call and cancel the enrollment.

(2) The REP or aggregator shall inform the customer that the authorization and verification portions of the call are being recorded.

(3) Authorizations and verifications shall be conducted in the same language as that used in the sales transaction.

(4) Required authorization disclosures. Prior to requesting verification of the move-in or switch request, a REP or aggregator shall clearly and conspicuously disclose the following information:

(A) the name of the new REP;

(B) the name of the specific electric service package or plan for which the applicant's assent is attained;

(C) the price of the product or plan, including the total price stated in cents per kilowatt-hour, for electric service;

(D) term or length of the term of service;

(E) the presence or absence of early termination fees or penalties, and applicable amounts;

(F) any requirement to pay a deposit and the estimated amount of that deposit, or the method in which the deposit will be calculated or the method in which the deposit will be calculated. An affiliated REP or POLR shall also notify the applicant of the right to post a letter of guarantee in lieu of a deposit in accordance with §25.478(i) of this title;

(G) any fees to the applicant for switching to the REP pursuant to subsection (n) of this section;

(H) in the case of a switch, the applicant's right, pursuant to subsection (j) of this section, to review and rescind the terms of service within three federal business days, after receiving the terms of service, without penalty;

(I) a statement that the applicant will receive a written copy of the terms of service document that will explain all the terms of the agreement and how to exercise the right of rescission, if applicable; and

(J) if the customer is being enrolled for prepaid service as defined by §25.498(b)(7) of this title, that the customer will not receive a bill and may request a summary of usage and payment.

(5) Verification of authorization of telephonic enrollment.

(A) A REP or aggregator shall electronically record on audio tape, a wave sound file, or other recording device the entirety of an applicant's verification of the authorization. The REP or aggregator shall inform the applicant that the verification call is being recorded.

(B) Prior to final confirmation by the applicant that they wish to enroll with the REP, the REP shall, at a minimum:

(i) obtain or confirm the applicant's billing name, billing address, and service address;

(ii) obtain or confirm the applicant's ESI-ID, if available;

(iii) for a move-in request, ask the applicant, "do you agree to become a customer with (REP) and allow (REP) to complete the tasks required to start your electric service?" and the applicant must answer affirmatively; or

(iv) for a switch request, ask the applicant, "do you agree to become a (REP) customer and allow us to complete the tasks required to switch your electric service from your current REP to (REP)?" and the applicant must answer affirmatively;

(v) ask the applicant, "do you want to receive information in English, Spanish (or the language used in the marketing of service to the applicant)?" The REP shall provide a means of documenting the applicant's language preference; and

(vi) obtain or confirm one of the following account access verification data: last four digits of the social security number, mother's maiden name, city or town of birth, or month and day of birth, driver's license or government issued identification number. For non-residential applicants, a REP may obtain the applicant's federal tax identification number.

(C) In the event the applicant does not consent to or does not provide any of the information listed in subparagraph (B) of this paragraph, the enrollment shall be deemed invalid and the REP shall not submit a switch or move-in request for the applicant's service.

(D) If a REP has solicited service for prepaid service, an actual pre-payment by a customer may be substituted for a telephonic verification, provided that the pre-payment is not taken at the time of the solicitation by the sales representative that has obtained the authorization from the customer, and the REP has obtained a written LOA from the customer and can produce documentation of the pre-payment. The REP shall not submit a move-in or switch request until it has received the prepayment from the customer.

(i) **Record retention**.

(1) A REP or aggregator shall maintain non-public records of each applicant's authorization and verification of enrollment for 24 months from the date of the REP's initial enrollment of the applicant and shall provide such records to the applicant, customer, or commission staff, upon request.

(2) A REP or an aggregator shall submit copies of its sales script, terms of service document, and any other materials used to obtain a customer's authorization or verification to the commission staff upon request. In the event commission staff request documents under this subsection, the requested records must be delivered to the commission staff within 15 days of the written request, unless otherwise agreed to by commission staff.

(3) In the event an applicant or customer disputes an enrollment or switch, the REP shall provide to the applicant or customer proof of the applicant's or customer's authorization within five business days of the request.

(j) **Right of rescission**. A REP shall promptly provide the applicant with the terms of service document after the applicant has authorized the REP to provide service to the applicant and the authorization has been verified. For switch requests, the REP shall offer the applicant a right to rescind the terms of service without penalty or fee of any kind for a period of three federal business days after the applicant's receipt of the terms of service document. The provider may assume that any delivery of the terms of service document deposited first class with the United States Postal Service will be received by the applicant within three federal business days. Any REP receiving an untimely notice of rescission from the applicant shall inform the applicant that the applicant has a right to select another REP and may do so by contacting that REP. The REP shall also inform the applicant that the applicant will be responsible for charges from the REP for service provided until the applicant switches to another REP. The right of rescission is not applicable to an applicant requesting a move-in.

(k) **Submission of an applicant's switch or move-in request to the registration agent**. A REP shall submit a move-in or switch request to the registration agent so that the move-in or switch will be processed on the approximate scheduled date agreed to by the applicant and as allowed by the tariff of the TDU, municipally owned utility, or electric cooperative. A REP shall submit an applicant's switch request to the registration agent as a standard switch. In the alternative, the REP shall submit an applicant's switch request as a self-selected switch if the applicant requests a specific date for a switch, consistent with the applicable transmission and distribution tariff. A REP may submit an applicant's switch request to the registration agent prior to the expiration of the rescission period prescribed by subsection (j) of this section, provided that if the customer makes a timely request to cancel service the REP shall take action to ensure that the switch is canceled or the customer is promptly returned to its chosen REP without inconvenience or additional cost to the customer. The applicant shall be informed of the approximate scheduled date that the applicant will begin receiving electric service from the REP, and of any delays in meeting that date, if known by the REP.

(l) **Duty of the registration agent**.

(1) When the registration agent receives a move-in or switch request from a REP, the registration agent shall process that request in accordance with this section and its protocols, to the extent that the protocols are consistent with this section. The registration agent shall send a switch notification notice to the applicant that shall:

(A) be worded in English and Spanish consistent with §25.473(d) of this title (relating to Non-English Language Requirements);

(B) identify the REP that initiated the switch request; and

(C) provide the names and telephone numbers for the gaining and losing REP.

(2) The registration agent shall direct the TDU to implement any switch, move-in, or transfer to the REP or the POLR in accordance with this section and its protocols.

(m) **Exemptions for certain transfers**. The provisions of this section relating to authorization and right of rescission are not applicable when the applicant's or customer's electric service is:

(1) transferred to the POLR pursuant to §25.43 of this title (relating to Provider of Last Resort (POLR)) when the customer's REP of record defaults or otherwise ceases to provide service. Nothing in this subsection implies that the customer is accepting a contract with the POLR for a specific term;

(2) transferred to the competitive affiliate of the POLR pursuant to §25.43(o) of this title;

(3) transferred to another REP in accordance with section §25.493 of this title (relating to Acquisition and Transfer of Customers from One Retail Electric Provider to Another); or

(4) transferred from one premise to another premise without a change in REP and without a material change in the terms of service.

(n) **Fees**. A REP, other than a municipally owned utility or an electric cooperative, shall not charge a fee to an applicant to switch to, select, or enroll with the REP unless an applicant without a Provisioned Advanced Meter requests an out-of-cycle meter read for the purpose of a self-selected switch. The registration agent shall not charge a fee to the end-use customer for the switch or enrollment process performed by the registration agent. The TDU shall not charge a fee for a review or adjustment described in subsection (p)(2) of this section. To the extent that the TDU assesses a REP a properly tariffed charge for connection of service, out-of-cycle meter read for self-selected switch requests, service order cancellations, or changes associated with the switching of service or the establishment of new service, any such fee may be passed on to the applicant or customer by the REP. A TDU shall not assess to a REP or an applicant any costs associated with a switch cancellation, including inadvertent gain fees, that results from the applicant's exercise of the three-day right of rescission. The TDU shall include such costs in the cost recovery mechanism described in subsection (o) of this section.

(o) **TDU cost recovery**. The TDU may recover the reasonable costs associated with performing meter reads for purposes of a standard switch through one of the following two options at the TDU's discretion:

(1) TDU costs associated with performing standard meter reads for the purpose of switches, to the extent not reflected in base rates, shall be considered costs incurred in deploying advanced metering functionality and are to be considered in setting a surcharge established under PURA §39.107 (h) and §25.130 of this title (relating to Advanced Metering). The costs shall be included in the annual reports filed pursuant to §25.130(k)(5) of this title as actual costs spent to date in the deployment of Advanced Metering Systems (AMS) and shall be considered in setting, reconciling and or updating the AMS surcharge pursuant to §25.130(k) of this title; or,

(2) a TDU shall create a regulatory asset for the expenses associated with performing standard meter reads for the purpose of switches pursuant to this subsection. Upon review of reasonableness and necessity, a reasonable level of amortization of such a regulatory asset, including carrying charges, shall be included as a recoverable cost in the TDU's rates in its next rate case or such other rate recovery proceeding as deemed necessary.

(p) **Meter reads for the purpose of a standard switch**.

(1) Beginning December 1, 2009, a TDU shall perform actual, as opposed to estimated, meter reads for at least 80% of meter reads for the purpose of a standard switch in any given month, and at least 95% of meter reads for the purpose of a standard switch in any calendar year, exclusive of remote meter reads using advanced meters. Until December 1, 2009, a TDU may perform estimated meter reads for standard switch requests only for residential customers, exclusive of customers with meters that have remote read capability. A TDU shall use best efforts to perform as many actual reads as possible for standard switches.

(2) Notwithstanding §25.214 of this title (relating to Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities), an estimated meter read for the purpose of a standard switch is not subject to adjustment, except as provided in subparagraph (A) or (B) of this paragraph. A customer is obligated to pay a bill based upon an estimated meter read for the purpose of a switch, including any adjustment made pursuant to subparagraph (A) or (B) of this paragraph.

(A) The TDU shall adjust the estimated meter read if the losing REP's billed usage is greater than the total kilowatt-hours used by the customer in the TDU monthly meter read cycle during which the estimate was made.

(B) Only upon the receipt of a customer dispute of the estimated usage to either the gaining or losing REP, either REP may request the TDU to review the estimate. In reviewing the estimate, the TDU shall promptly calculate the average actual kWh usage per day for the time period from the actual meter reading occurring prior to the estimated reading to the actual meter reading occurring after the estimated reading. The TDU shall determine whether the usage per day for the estimated period prior to the switch is at least 25% greater than, or 25% less than, the average actual kWh usage per day. If so, the TDU shall promptly adjust the estimated meter read. The TDU may adjust an estimate that does not meet this 25% threshold, on a non-discriminatory basis.

(C) The TDU shall apply a reasonable methodology in making adjustments pursuant to subparagraphs (A) and (B) of this paragraph and shall make the methodology available to REPs. Consistent with any meter read adjustments, the TDU shall adjust its invoices to the affected REP or REPs.

(3) A TDU shall file performance reports with the commission as part of the information filed under §25.88 of this title (relating to Retail Market Performance Measure Reporting). These reports shall show by month the number and percentages of actual and estimated meter reads for the purpose of switches, and whether that month's performance was in compliance with paragraph (1) of this subsection.

(q) **Scheduled switch date**. Once a TDU notifies the REPs of a scheduled switch date, the TDU shall perform an actual or estimated read of the customer's meter for that date.

§25.475. General Retail Electric Provider Requirements and Information Disclosures to Residential and Small Commercial Customers.

(a) **Applicability**. The requirements of this section apply to retail electric providers (REPs) and aggregators, when specifically stated, in connection with the provision of service and marketing to residential and small commercial customers. This section is effective April 1, 2010. REPs are not required to modify contract documents related to contracts entered into before this date, but shall provide notice of expiration as required by subsection (e) of this section.

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

(1) **Contract** -- The Terms of Service document (TOS), the Electricity Facts Label (EFL), Your Rights as a Customer document (YRAC), and the documentation of enrollment pursuant to §25.474 of this title (relating to Selection of Retail Electric Provider).

(2) **Contract documents** -- The TOS, EFL and YRAC.

(3) **Contract expiration** -- The time when the initial term contract is completed. A new contract is initiated when the customer begins receiving service pursuant to the new EFL.

(4) **Contract term** -- The time period the contract is in effect.

(5) **Fixed rate product** -- A retail electric product with a term of at least three months for which the price (including recurring charges) for each billing period of the contract term is the same throughout the contract term, except that the price may vary from the disclosed amount solely to reflect actual changes in the Transmission and Distribution Utility (TDU) charges, changes to the Electric Reliability Council of Texas (ERCOT) or Texas Regional Entity administrative fees charged to loads or changes resulting from federal, state or local laws that impose new or modified fees or costs on a REP that are beyond the REP's control.

(6) **Indexed product** -- A retail electric product for which the price, including recurring charges, can vary according to a pre-defined pricing formula that is based on publicly available indices or information and is disclosed to the customer, and to reflect actual changes in TDU charges, changes to the ERCOT or Texas Regional Entity administrative fees charged to loads or changes resulting from federal, state or local laws or regulatory actions that impose new or modified fees or costs on a REP that are beyond the REPs control. An indexed product may be for a term of three months or more, or may be a month-to-month contract.

(7) **Month-to-month contract** -- A contract with a term of 31 days or less. A month-to-month contract may not contain a termination fee or penalty.

(8) **Price** -- The cost for a retail electric product that includes all recurring charges excluding state and local sales taxes, and reimbursement for the state miscellaneous gross receipts tax.

(9) **Recurring charge** -- A charge for a retail electric product that is expected to appear on a customer's bill in every billing period or appear in three or more billing periods in a twelve month period. A charge is not considered recurring if it will be billed by the TDU and passed on to the customer and will either not be applied to all customers of that class within the TDU territory, or cannot be known until the customer enrolls or requests a specific service.

(10) **Term contract** -- A contract with a term in excess of 31 days.

(11) **Variable price product** -- A retail product for which price may vary according to a method determined by the REP, including a product for which the price, can increase no more than a defined percentage as indexed to the customer's previous billing month's price. For residential customers, a variable price product can be only a month-to-month contract.

(c) **General Retail Electric Provider requirements.**

(1) **General Disclosure Requirements.**

(A) All written, electronic, and oral communications, including advertising, websites, direct marketing materials, billing statements, TOSs, EFLs and YRACs distributed by a REP or aggregator shall be clear and not misleading, fraudulent, unfair, deceptive, or anti-competitive. Prohibited communications include, but are not limited to:

(i) Using the term or terms "fixed" to market a product that does not meet the definition of a fixed rate product.

(ii) Suggesting, implying, or otherwise leading someone to believe that a REP or aggregator has been providing retail electric service prior to the time the REP or aggregator was certified or registered by the commission.

(iii) Suggesting, implying or otherwise leading someone to believe that receiving retail electric service from a REP will provide a customer with better quality of service from the TDU.

(iv) Falsely suggesting, implying or otherwise leading someone to believe that a person is a representative of a TDU or any REP or aggregator.

(v) Falsely suggesting, implying or otherwise leading someone to believe that a contract has benefits for a period of time longer than the initial contract term.

(B) Written and electronic communications shall not refer to laws, including commission rules without providing a link or website address where the text of those rules are available. All printed advertisements, electronic advertising over the Internet, and websites, shall include the REP's certified name or commission authorized business name, or the aggregator's registered name, and the number of the certification or registration.

(C) The TOS, EFL, and YRAC shall be provided to each customer upon enrollment. Each document shall be provided to the customer whenever a change is made to the specific document and upon a customer's request, at any time free of charge.

(D) A REP shall retain a copy of each version of the TOS, EFL, and YRAC during the time the plan is in effect for a customer and for four years after the contract ceases to be in effect for any customer. REPs shall provide such documents at the request of the commission or its staff.

(2) **General contracting requirements.**

(A) A TOS, EFL, and YRAC shall be complete, shall be written in language that is clear, plain and easily understood, and shall be printed in paragraphs of no more than 250 words in a font no smaller than 10 point. References to laws including commission rules in these documents shall include a link or internet address to the full text of the law.

(B) All contract documents shall be available to the commission to post on its customer education website (if the REP chooses to post offers to the website).

(C) A contract is limited to service to a customer at a location specified in the contract. If the customer moves from the location, the customer is under no obligation to continue the contract at another location. The REP may require a customer to provide evidence that it is moving. There shall be no early termination fee assessed to the customer as a result of the customer's relocation if the customer provides a forwarding address and, if required, reasonable evidence that the customer no longer occupies the location specified in the contract.

(D) A TOS and EFL shall disclose the type of product being described, using one of the following terms: fixed rate product, indexed product or a variable price product.

(E) A REP shall not use a credit score, a credit history, or utility payment data as the basis for determining the price for electric service for a product with a contract term of 12 months or less for an existing residential customer or in response to an applicant's request to become a residential customer.

(F) In any dispute between a customer and a REP concerning the terms of a contract, any vagueness, obscurity, or ambiguity in the contract will be construed in favor of the customer.

(G) For a variable price product, the REP shall disclose on the REP's website and through a toll-free number the current price and, for residential customers, one year price history, or history for the life of the product, if it has been offered less than one year. A REP shall not rename a product in order to avoid disclosure of price history. The EFL of a variable price product or indexed product shall include a notice of how the current price and, if applicable, historical price information may be obtained.

(H) A REP shall comply with its contracts.

(3) **Specific contract requirements.**

(A) The contract term shall be conspicuously disclosed.

(B) The start and end dates of the contract shall be available to the customer upon request. If the REP cannot determine the start date, the REP may estimate the start date. After the start date is known, the REP shall specify the end date of the contract by:

(i) specifying a calendar date; or

(ii) reference to the first meter read on or after a specific calendar date.

(C) If a REP specifies a calendar date as the end date, the REP may bill the term contract price through the first meter read on or after the end date of the contract.

(4) **Website requirements.**

(A) Each REP that offers residential retail electric products for enrollment on its website shall prominently display the EFL for any products offered without a person having to enter any personal information other than zip code and information that allows determination of the type of offer the consumer wishes to review. Person-specific information shall not be required.

(B) The EFL for each product shall be printable in no more than a two page format. The EFL, TOS, and YRAC for any products offered for enrollment on the website shall be available for viewing or downloading.

(d) **Changes in contract and price and notice of changes.** A REP may make changes to the terms and conditions of a contract or to the price of a product as provided for in this section. Changes in term (length) of a contract require the customer to enter into a new contract and may not be made by providing the notice described in paragraph (3) of this subsection.

(1) **Contract changes other than price.**

(A) A REP may not change the price (other than as allowed by paragraph (2) of this subsection) or contract term of a term contract for a retail electric product, during its term; but may change any other provision of the contract, with notice under paragraph (3) of this subsection.

(B) A REP may not change the terms and conditions of a month-to-month product, indexed or variable price products, unless it provides notice under paragraph (3) of this subsection.

(2) **Price changes.**

(A) A REP may only change the price of a fixed rate product, an indexed product, or a variable product consistent with the definitions in this section and according to the product's EFL. Such price changes do not require notice under paragraph (3) of this subsection.

(B) For a fixed rate product, each bill shall either show the price changes on one or more separate line items, or shall include a conspicuous notice stating that the amount billed may include price changes allowed by law or regulatory actions.

(C) Each residential bill for a variable price product shall include a statement informing the customer how to obtain information about the price that will apply on the next bill.

(3) **Notice of changes to terms and conditions**. A REP must provide written notice to its customers at least 14 days in advance of the date that the change in the contract will be applied to the customer's bill or take effect. Notice is not required for a change that benefits the customer.

(4) **Contents of the notice to change terms and conditions**. The notice shall:

(A) be provided in or with the customer's bill or in a separate document;
(B) include the following statement, "Important notice regarding changes to your contract" clearly and conspicuously in the notice;
(C) identify the change and the specific contract provisions that address the change;
(D) clearly specify what actions the customer needs to take if the customer does not accept the proposed changes to the contract;
(E) state in bold lettering that if the new terms are not acceptable to the customer, the customer may terminate the contract and no termination penalty shall apply for 14 days from the date that the notice is sent to the customer but may apply if action is taken after the 14 days have expired. No such statement is required if the customer would not be subject to a termination penalty under any circumstances; and
(F) state in bold lettering that establishing service with another REP may take up to seven business days.

(e) **Contract expiration and renewal offers.** The REP shall send a written notice of contract expiration at least 30 days or one billing cycle prior to the date of contract expiration, but no more than 60 days or two billing cycles in advance of contract expiration for a residential customer, and at least 14 days but no more than 60 days or two billing cycles in advance of contract expiration for a small commercial customer. The REP shall send the notice by mail to a residential customer or shall send the required notice to a customer's e-mail address if available to the REP and if the customer has requested to receive contract-related notices electronically. The REP shall send the notice to a small commercial customer by mail or may send the notice to the customer's e-mail address if available to the REP and, if the customer has requested to receive contract-related notices electronically. Nothing in this section shall preclude a REP from offering a new contract to the customer at any other time during the contract term.

(1) **Contract Expiration.**

(A) If a customer takes no action in response to a notice of contract expiration for the continued receipt of retail electric service upon the contract's expiration, the REP shall serve the customer pursuant to a default renewal product that is a month-to-month product.
(B) Written notice of contract expiration shall be provided in or with the customer's bill, or in a separate document.
(i) If notice is provided with a residential customer's bill, the notice shall be printed on a separate page. A statement shall be included on the outside of the envelope sent to a residential customer's billing address by mail and in the subject line on the e-mail (if the REP sends the notice by e-mail) that states, "Contract Expiration Notice. See Enclosed."
(ii) If the notice is provided in or with a small commercial customer's bill, the REP must include a statement on the outside of the billing envelope or in the subject line of an electronic bill that states, "Contract Expiration Notice" or "Contract Expiration Notice. See Enclosed."; or
(iii) If notice is provided in a separate document, a statement shall be included on the outside of the envelope and in the subject line of the e-mail (if customer has agreed to receive official documents by e-mail) that states, "Contract Expiration Notice. See Enclosed." for residential customers or for small commercial customers, "Contract Expiration Notice" or "Contract Expiration Notice. See Enclosed."
(C) A written notice of contract expiration (whether with the bill or in a separate envelope) shall set out the following:
(i) The date as provided for in subsection (c)(3)(B) of this section that the existing contract will expire.

(ii) If the REP provided a calendar date as the end date for the contract, a statement in bold lettering no smaller than 12 point font that no termination penalty shall apply to residential and small commercial customers 14 days prior to the date stated as the expiration date in the notice. In addition, a description of any fees or charges associated with the early termination of a residential customer's fixed rate product that would apply before 14 days prior to the date stated as the expiration date in the notice must be provided. No such statements are required if the original contract did not contain a termination fee.

(iii) If the REP defined the contract end date by reference to the first meter read on or after a specific calendar date, a statement in bold lettering no smaller than 12 point font that no termination penalty shall apply to residential customers after receipt of the contract expiration notice, or that no termination penalty shall apply to small commercial customers for 14 days prior to the contract end date. No such statement is required if the original contract did not contain a termination fee.

(iv) A description of any renewal offers the REP chooses to make available to the customer and the location of the TOS and EFL for each of those products and a description of actions the customer needs to take to continue to receive service from the REP under the terms of any of the described renewal offers and the deadline by which actions must be taken.

(v) A copy of the EFL for the default renewal product if the customer takes no action, or if the EFL is not included with the contract expiration notice, the REP must provide the EFL to the customer at least 14 days before the expiration of the contract using the same delivery method as was used for the notice. The contract expiration notice must specify how and when the EFL will be made available to the customer.

(vi) A statement that if the customer takes no action, service to the customer will continue pursuant to the EFL for the default renewal product that shall be included as part of the notice of contract expiration. The TOS for the default renewal product shall be included as part of the notice, unless the TOS applicable to the customer's existing service also applies to the default renewal product.

(vii) A statement that the default service is month-to month and may be cancelled at any time with no fee.

(2) **Affirmative consent.** A customer that is currently receiving service from a REP may be re-enrolled with the REP for service with the same product under which the customer is currently receiving service, or a different product, by conducting an enrollment pursuant to §25.474 of this title or by obtaining the customer's consent in a recording, electronic document, or written letter of authorization consistent with the requirements of this subsection. Affirmative consent is not required when a REP serves the customer under a default renewal product pursuant to paragraph (1) of this subsection. Each recording, electronic document, or written consent form must:

(A) Indicate the customer's name, billing address, service address (for small commercial customers, the ESI ID may be used rather than the service address);

(B) Indicate the identification number of the TOS and EFL under which the customer will be served;

(C) Indicate if the customer has received, or when the customer will receive copies of the TOS, EFL and YRAC;

(D) Indicate the price(s) which the customer is agreeing to pay;

(E) Indicate the date or estimated date of the re-enrollment, the contract term, and the estimated start and end dates of contract term;

(F) Affirmatively inquire whether the customer has decided to enroll for service with the product, and contain the customer's affirmative response; and

(G) Be entirely in plain, easily understood language, in the language that the customer has chosen for communications.

(f) **Terms of service document.** The following information shall be conspicuously contained in the TOS:

(1) **Identity and contact information**. The REP's certified name and business name (dba) (if applicable), mailing address, e-mail and Internet address (if applicable), certification number, and a toll-free telephone number (with hours of operation and time-zone reference).

(2) **Pricing and payment arrangements.**

(A) Description of the amount of any routine non-recurring charges resulting from a move-in or switch that may be charged to the customer, including but not limited to an out-of-cycle meter read, and connection or reconnection fees;

(B) For small commercial customers, a description of the demand charge and how it will be applied, if applicable;

(C) An itemization, including name and cost, of any non-recurring charges for services that may be imposed on the customer for the retail electric product, including an application fee, charges for default in payment or late payment, and returned checks charges;

(D) A description of any collection fees or costs that may be assessed to the customer by the REP and that cannot be quantified in the TOS; and

(E) A description of payment arrangements and bill payment assistance programs offered by the REP.

(3) **Deposits.** If the REP requires deposits from its customers:

(A) a description of the conditions that will trigger a request for a deposit;

(B) the maximum amount of the deposit or the manner in which the deposit amount will be determined;

(C) a statement that interest will be paid on the deposit at the rate approved by the commission, and the conditions under which the customer may obtain a refund of a deposit;

(D) an explanation of the conditions under which a customer may establish satisfactory credit pursuant to §25.478 of this title (relating to Credit Requirements and Deposits); and

(E) if applicable, the customer's right to post a letter of guarantee in lieu of a deposit pursuant to §25.478(i) of this title.

(4) **Rescission, Termination and Disconnection.**

(A) In a conspicuous and separate paragraph or box:

(i) A description of the right of a customer, for switch requests, to rescind service without fee or penalty of any kind within three federal business days after receiving the TOS, pursuant to §25.474 of this title; and

(ii) Detailed instructions for rescinding service, including the telephone number and, if available, facsimile number or e-mail address that the customer may use to rescind service.

(B) A statement as to how service can be terminated and any penalties that may apply;

(C) A statement of customer's ability to terminate service without penalty if customer moves to another premises and provides evidence that it is moving, if required, and a forwarding address; and

(D) If the REP has disconnection authority, pursuant to §25.483 of this title (relating to Disconnection of Service), a statement that the REP may order disconnection of the customer for non-payment.

(5) **Antidiscrimination.** A statement informing the customer that the REP cannot deny service or require a prepayment or deposit for service based on a customer's race, creed, color, national origin, ancestry, sex, marital status, lawful source of income, level of income, disability, familial

status, location of a customer in a economically distressed geographic area, or qualification for low income or energy efficiency services. For residential customers, a statement informing the customer that the REP cannot use a credit score, a credit history, or utility payment data as the basis for determining the price for electric service for a product with a contract term of 12 months or less.

(6) **Other terms.** Any other material terms and conditions, including exclusions, reservations, limitations of liability, or special equipment requirements, that are a part of the contract for the retail electric product.

(7) **Contract expiration notice.** For a term contract, the TOS shall contain a statement informing the customer that a contract expiration notice will be sent at least 14 days prior to the end of the initial contract term. The TOS shall also state that if the customer fails to take action to ensure the continued receipt of retail electric service upon the contract's expiration, the customer will continue to be served by the REP automatically pursuant to a default renewal product, which shall be a month-to-month product.

(8) A statement describing the conditions under which the contract can change and the notice that will be provided if there is a change.

(9) **Version number.** A REP shall assign an identification number to each version of its TOS, and shall publish the number on the terms of service document.

(g) **Electricity Facts Label.** The EFL shall be unique for each product offered and shall include the information required in this subsection. Nothing in this subsection precludes a REP from charging a price that is less than its EFL would otherwise provide.

(1) **Identity and contact information**. The REP's certified name and business name (dba) (if applicable), mailing address, e-mail and Internet address (if applicable), certification number, and a toll-free telephone number (with hours of operation and time-zone reference).

(2) **Pricing disclosures.** Pricing information shall be disclosed by a REP in an EFL. The EFL shall state specifically whether the product is a fixed rate, variable price or indexed product.

(A) For a fixed rate product, the EFL shall provide the total average price for electric service reflecting all recurring charges, excluding state and local sales taxes, and reimbursement for the state miscellaneous gross receipts tax, to the customer.

(B) For an indexed product, the EFL shall provide sample prices for electric service reflecting all recurring charges, excluding state and local sales taxes, and reimbursement for the state miscellaneous gross receipts tax, resulting from a reasonable range of values for the inputs to the pre-defined pricing formula.

(C) For a variable price product, the EFL shall provide the total average price for electric service for the first billing cycle reflecting all recurring charges, including any TDU charges that may be passed through and excluding state and local sales taxes, and reimbursement for the state miscellaneous gross receipts tax, to the customer. Actual changes in TDU charges, changes to the ERCOT or Texas Regional Entity administrative fees charge to loads or changes resulting from federal, state or local laws or regulatory actions that impose new or modified fees or costs on a REP that were not implemented prior to the issuance of the EFL and were not included in the average price calculation may be directly passed through to customers beginning with the customer's first billing cycle.

(D) The total average price for electric service shall be expressed in cents per kilowatt hour, rounded to the nearest one-tenth of one cent for the following usage levels:

(i) For residential customers, 500, 1,000 and 2,000 kilowatt hours per month; and

(ii) For small commercial customers, 1,500, 2,500, and 3,500 kilowatt hours per month. If demand charges apply assume a 30 percent load factor.

(E) If a REP combines the charges for retail electric service with charges for any other product, the REP shall:

(i) If the electric product is sold separately from the other products, disclose the total price for electric service separately from other products; and

(ii) If the REP does not permit a customer to purchase the electric product without purchasing the other products or services, state the total charges for all products and services as the price of the total electric service. If the product has a one-time cost up front, for the purposes of the average price calculation, the cost of the product may be figured in over a 12-month period with 1/12 of the cost being attributed to a single month.

(F) The following shall be included on the EFL for specific product types:

(i) For indexed products, the formula used to determine an indexed product, including a website and phone number customers may contact to determine the current price.

(ii) For a variable price product that increases no more than a defined percentage as indexed to the customer's previous billing month's price, a notice in bold type no smaller than 12 point font: "Except for price changes allowed by law or regulatory action, this price is the price that will be applied during your first billing cycle; this price may increase by no more than {insert percentage} percent from month-to-month." For residential customers, the following additional statement is required: "Please review the historical price of this product available at {insert specific website address and toll-free telephone number}." In the disclosure chart, the box describing whether the price can change during the contract period shall include the following statement: "The price applied in the first billing cycle may be different from the price in this EFL if there are changes in TDSP charges; changes to the Electric Reliability Council of Texas or Texas Regional Entity administrative fees charged to loads; or changes resulting from federal, state or local laws or regulatory actions that impose new or modified fees or costs that are outside our control."

(iii) For all other variable price products, a notice in bold type no smaller than 12 point font: "Except for price changes allowed by law or regulatory action, this price is the price that will be applied during your first billing cycle; this price may change in subsequent months at the sole discretion of {insert REP name}. In the disclosure chart, the box describing whether the price can change during the contract period shall include the following statement: "The price applied in the first billing cycle may be different from the price in this EFL if there are changes in TDSP charges; changes to the Electric Reliability Council of Texas or Texas Regional Entity administrative fees charged to loads; or changes resulting from federal, state or local laws or regulatory actions that impose new or modified fees or costs that are outside our control." For residential customers, the following additional statement is required: "Please review the historical price of this product available at {insert specific website address and toll-free telephone number}."

(3) **Fee Disclosures.**

(A) If customers may be subject to a special charge for underground service or any similar charge that applies only in a part of the TDU service area, the EFL shall include a statement in the electricity price section that some customers will be subject to a special charge that is not included in the total average price for electric service and shall disclose how the customer can determine the price and applicability of the special charge.

(B) A listing of all fees assessed by the REP that may be charged to the customer and whether the fee is included in the recurring charges.

(4) **Term Disclosure.** EFL shall include disclosure of the length of term, minimum service term, if any, and early termination penalties, if any.

(5) **Renewable Energy Disclosures.** The EFL shall include the percentage of renewable energy of the electricity product and the percentage of renewable energy of the statewide average generation mix.

(6) **Format of Electricity Facts Label.** REPs must use the following format for the EFL with the pricing chart and disclosure chart shown. The additional language is for illustrative purposes. It does not include all reporting requirements as outlined above. Such subsections should be referred to for determination of the required reporting items on the EFL. Each EFL shall be printed in type no smaller than ten points in size, unless a different size is specified in this section, and shall be formatted as shown in this paragraph:

Electricity Facts Label (EFL)
{Name of REP}, {Name of Product}, {Service area *(if applicable)*},
{Date}

Electricity price

Average Monthly Use	500kWh	1,000kWh	2,000kWh
Average price per kWh	{x.x}¢	{x.x}¢	{x.x}¢
For POLR use: Minimum price per kilowatt-hour.	{x.x}¢	{x.x}¢	{x.x}¢

{If applicable} On-peak {season or time}:{xxx}
{If applicable} Average on-peak price per kilowatt-hour: {x.x}¢
{If applicable} Average off-peak price per kilowatt-hour: {x.x}¢
{If applicable} Potential surcharges corresponding to the given electric service.
{If variable that does not change within a defined percentage} **Except for price changes allowed by law or regulatory action, this price is the price that will be applied during your first billing cycle; this price may change in subsequent months at the sole discretion of {insert REP name}.** {If residential} **Please review the historical price of this product available at {insert website address and toll-free number}.**

{If variable that changes within a defined percentage}
Except for price changes allowed by law or regulatory action, this price is the price that will be applied during your first billing cycle; this price may increase by no more than {insert percentage} percent from month-to-month. {If residential} **Please review the historical price of this product available at {insert website address and toll-free number}.**

Other Key Terms and questions	*See Terms of Service statement for a full listing of fees, deposit policy, and other terms.*	
Disclosure Chart	Type of Product	(fixed rate indexed or variable)
	Contract Term	(number of months)
	Do I have a termination fee or any fees associated with terminating service?	(yes/no) (if yes, how much)
	Can my price change during contract period?	(yes/no)
	If my price can change, how will it change, and by how much?	(formula/description of the way the price will vary and how much it can change) In addition if the REP chooses to pass through regulatory changes the following shall be required: "The price applied in the first billing cycle may be different from the price in this EFL if there are changes in TDSP charges; changes to the Electric Reliability Council of Texas or Texas Regional Entity administrative fees charged to loads; or changes resulting from federal, state or local laws or regulatory actions that impose new or modified fees or costs that are outside our control."
	What other fees may I be charged?	(List, or give direct location in TOS.)
	Is this a pre-pay or pay in advance product	(yes/no)
	Does the REP purchase excess distributed renewable generation?	(yes/no)
	Renewable Content	(This product is x% renewable)
	The statewide average for renewable content is	(% of statewide average for renewable content)
	Contact info, certification number, version number *Additional information may be added below.*	

<u>*Type used in this format*</u>
Title: 12 point
Headings: 12 point boldface
Body: 10 point

(7) **Version number.** A REP shall assign an identification number to each version of its EFL, and shall publish the number on the EFL.

(h) **Your Rights as a Customer disclosure.** The information set out in this section shall be included in a REP's "Your Rights as a Customer" document, to summarize the standard customer protections provided by this subchapter or additional protections provided by the REP.

(1) A YRAC document shall be consistent with the TOS for the retail product.

(2) The YRAC document shall inform the customer of the REP's complaint resolution policy pursuant to §25.485 of this title (relating to Customer Access and Complaint Handling) and payment arrangements and deferred payment policies pursuant to §25.480 of this title (relating to Bill Payment and Adjustments).

(3) The YRAC document shall inform the customer of the REP's procedures for reporting outages and the steps necessary to have service restored or reconnected after an involuntary suspension or disconnection.

(4) The YRAC document shall inform the customer of the customer's right to have the meter tested pursuant to §25.124 of this title (relating to Meter Testing), or in accordance with the tariffs of a transmission and distribution utility, a municipally owned utility, or an electric cooperative, as applicable, and the REP's ability in all cases to make that request on behalf of the customer by a standard electronic market transaction, and the customer's right to be instructed on how to read the meter, if applicable.

(5) The YRAC document shall inform the customer of the availability of:

(A) Financial and energy assistance programs for residential customers;

(B) Any special services such as readers or notices in Braille or TTY;

(C) Special policies or programs available to residential customers with physical disabilities, including residential customers who have a critical need for electric service to maintain life support systems; and

(D) Any available discounts that may be offered by the REP for qualified low-income residential customers. A REP may comply with this requirement by providing the customer with instructions for how to inquire about such discounts.

(6) The YRAC document shall inform the customer of the following customer rights and protections:

(A) Unauthorized switch protections applicable under §25.495 of this title (relating to Unauthorized Change of Retail Electric Provider);

(B) The customer's right to dispute unauthorized charges on the customer's bill as set forth in §25.481 of this title (relating to Unauthorized Charges);

(C) Protections relating to disconnection of service pursuant to §25.483 of this title;

(D) Non-English language requirements pursuant to §25.473 of this title (relating to Non-English Language Requirements);

(E) Availability of a Do Not Call List pursuant to §25.484 of this title (relating to Electric No-Call List) and §26.37 of this title (relating to Texas No-Call List); and

(F) Privacy rights regarding customer proprietary information as provided by §25.472 of this title (relating to Privacy of Customer Information).

(7) **Identity and contact information**. The REP's certified name and business name (dba), certification number, mailing address, e-mail and Internet address (if applicable), and a toll-free telephone number (with hours of operation and time-zone reference) at which the customer may obtain information concerning the product.

(i) **Advertising claims.** If a REP or aggregator advertises or markets the specific benefits of a particular electric product, the REP or aggregator shall provide the name of the electric product offered in the advertising or marketing materials to the commission or its staff, upon request. All advertisements and marketing materials distributed by or on behalf of a REP or aggregator shall comply with this section.

REPs and aggregators are responsible for representations to customers and prospective customers by employees or other agents of the REP concerning retail electric service that are made through advertising, marketing or other means.

(1) **Print advertisements.** Print advertisements and marketing materials, including direct mail solicitations that make any claims regarding price, savings, or environmental quality for an electricity product of the REP compared to a product offered by another REP shall include the EFL of the REP making the claim. In lieu of including an EFL, the following statement shall be provided: "You can obtain important standardized information that will allow you to compare this product with other offers. Contact (name, telephone number, and Internet address (if available) of the REP)." If the REPs phone number or website address is included on the advertisement, such phone number or website address is not required in the disclaimer statement. Upon request, a REP shall provide to the commission the contract documents relating to a product being advertised and any information used to develop or substantiate comparisons made in the advertisement.

(2) **Television, radio, and internet advertisements.** A REP shall include the following statement in any television, Internet, or radio advertisement that makes a specific claim about price, savings, or environmental quality for an electricity product of the REP compared to a product offered by another REP: "You can obtain important standardized information that will allow you to compare this product with other offers. Contact (name, telephone number and website (if available) of the REP)." If the REPs phone number or website address is included on the advertisement, such phone number or website address is not required in the disclaimer statement. This statement is not required for general statements regarding savings or environmental quality, but shall be provided if a specific price is included in the advertisement, or if a specific statement about savings or environmental quality compared to another REP is made. Upon request, a REP shall provide to the commission the contract documents relating to a product being advertised and any information used to develop or substantiate comparisons made in the advertisement.

(3) **Outdoor advertisements**. A REP shall include, in a font size and format that is legible to the intended audience, its certified name or commission authorized business name, certification number, telephone number and Internet address (if available).

(4) **Renewable energy claims.** A REP shall authenticate its sales of renewable energy in accordance with §25.476 of this title (relating to Renewable and Green Energy Verification). If a REP relies on supply contracts to authenticate its sales of renewable energy, it shall file a report with the commission, not later than March 15 of each year demonstrating its compliance with this paragraph and §25.476 of this title.

§25.476. Renewable and Green Energy Verification.

(a) **Purpose.** The purpose of this section is to establish the procedures by which retail electric providers (REPs) calculate and compose their renewable content pursuant to §25.475 of this title (relating to General Retail Electric Provider Requirements and Information Disclosures to Residential and Small Commercial Customers) and to establish guidelines and verification for claims of "green" products.

(b) **Application.**

(1) This section applies to all REPs. Additionally, some of the reporting requirements established in this section apply to the registration agent and to all owners of generation assets as defined in subsection (c) of this section.

(2) Nothing in this section shall be construed as protecting a REP against prosecution under deceptive trade practices statutes.

(3) In accordance with the Public Utility Regulatory Act (PURA) §39.001(b)(4), the commission and the registration agent will ensure the confidentiality of competitively sensitive information, reported to the commission or the registration agent under this section.

(c) **Definitions**. The definitions set forth in §25.471(d) of this title (relating to General Provisions of Customer Protection Rules) apply to this section. In addition, the following words and terms, when used in this section, shall have the following meanings unless the context indicates otherwise:

(1) **Default scorecard** -- The estimated fuel mix and environmental impact of all electricity in Texas that is not authenticated by retiring renewable energy credits (RECs).

(2) **Generation owner** -- A power generation company, river authority, municipally owned utility, electric cooperative, or any other entity that owns electric generating facilities in the state of Texas.

(3) **Generator scorecard** -- The aggregated fuel mix and environmental impact of all generating facilities located in Texas that are owned by the same generation owner.

(4) **New product** -- An electricity product during the first year it is marketed to customers.

(5) **Renewable energy credit offset (REC offset) --** A non-tradable allowance as defined and created by §25.173 of this title (relating to Goal for Renewable Energy). For the purposes of this section, a REC offset authenticates the renewable attributes, but not the quantity, of generation produced by its associated facility.

(d) **Marketing standards for "green" and "renewable" electricity products.**

(1) A REP may market an electricity product as "green" if:

(A) All of the product's fuel mix is renewable energy as defined in PURA §39.904(d), Texas natural gas as specified in PURA §39.904(d)(2), or a combination thereof; and

(B) All statements representing the product as "green," if not containing 100% renewable energy, as defined in PURA §39.904(d), include a footnote, parenthetical note, or other obvious disclaimer that "A 'green' product may include Texas natural gas and renewable energy.

(2) A REP may market an electricity product as "renewable" or label an electricity product on the EFL as "renewable" only if:

(A) All of the product's fuel mix is renewable energy as defined in PURA §39.904(d); or

(B) All statements representing the product as "renewable" use the format "x% renewable," where "x" is the product's renewable energy fuel mix percentage.

(3) If a REP makes marketing claims about a product's "green" content on the basis of its use of natural gas as a fuel, the REP must include with the report required under subsection (f)(1) of this section proof that the natural gas used to generate the electricity was produced in Texas.

(e) **Compilation of scorecard data.**

(1) The registration agent shall create and maintain a database of generator scorecards reflecting each generation owner's company-wide fuel mix and environmental impact data based on generating facilities located in Texas.

(2) Each generation owner's fuel mix and environmental impact data for the preceding calendar year shall be published on the registration agent's Internet web site by April 1 of each year and shall state:

(A) the percentage of MWhs generated from each of the following fuel sources: coal and lignite, natural gas, nuclear, renewable energy, and other sources; and

(B) the MWh-weighted average annual emissions rates in pounds per 1,000 kWh for the aggregate generation sources of the generation owner for carbon dioxide, nitrogen oxides, particulates, sulfur dioxide, and spent nuclear fuel produced (with spent nuclear fuel annualized using standard industry conversion factors).

(3) Not later than March 1 of each year, each generation owner shall report to the registration agent the following data for the preceding calendar year: net generation in MWh from each of its generating units in Texas; the type of fuel used by each of its generating units in Texas; and the MWh-weighted average annual emissions rate, on an aggregate basis for all of its generating units in Texas (in pounds per 1,000 kWh) for carbon dioxide, nitrogen oxides, particulates, sulfur dioxide, and nuclear waste. For purposes of calculating its average emissions rates, each generation owner shall rely upon emissions data that it submits to the United States Environmental Protection Agency (EPA), the Texas Commission on Environmental Quality (TCEQ), or the best available data if the generation owner does not submit pertinent data to the EPA or TCEQ. A generation owner shall not be required to submit information to the registration agent regarding the net generation of its generating units located within the Electric Reliability Council of Texas (ERCOT) region if, upon request, the registration agent advises the owner of generation assets that it already has such information available from its polled settlement meter data.

(4) Not later than April 1 of each year, the registration agent shall calculate and publish on its Internet website a state average fuel mix, statewide system average emission rates for each type of emission, and a default scorecard to account for all electric generation in the state that is not authenticated as defined in subsection (c)(1) of this section.

(A) The default fuel mix shall be the percentage of total MWh of generation not authenticated that has been obtained from each fuel type.

(B) Default emission rates for each type of emission shall be calculated by dividing total pounds of emissions or waste by total MWh, using data only for generation not authenticated.

(f) **Calculating renewable generation and authenticating "green" claims.**

(1) Not later than March 15 of each year, each REP shall report to the registration agent attestations from power generators that the natural gas used to generate electricity supplied to the REP was produced in Texas, if during the preceding calendar year and the current calendar year the REP markets "green" electricity on the basis of that power.

(2) For power purchased from sources outside of Texas, a supply contract between a REP and the owner of a generating facility may be used to authenticate the fuel mix for electricity generated at that facility and sold at retail in Texas.

(A) The contract must identify a specific generating facility from which the REP has obtained electricity that it sold to retail customers in Texas during the preceding calendar year.

(B) A REP that intends to rely upon a supply contract with an out-of-state generator to authenticate fuel mix shall submit a report to the registration agent for the specified generating facility no later than March 1 of each year that reports the facility's annual fuel mix.

(3) For the purposes of EFL disclosures, the retirement of RECs shall be the only method of authenticating generation for which a REC has been issued under §25.173 of this title. The retirement of a REC shall be equivalent to one megawatt-hour of generation from renewable resources. The use of RECs to authenticate the use of renewable fuels must be consistent with REC account information maintained by the Renewable Energy Credits Trading Program Administrator. A REC offset may be used to authenticate the renewable attributes of the current MWh output from its associated supply contract.

(4) In determining the renewable content percentages to be disclosed on the EFL for a product pursuant to §25.475 of this title, the REP shall rely upon the following sources of information: the Texas State Average Fuel Mix published by the registration agent under subsection (e) of this section; retired RECs; and actual energy production during the calendar year from resources that are awarded REC offsets by the REC program administrator. The REP may also rely on power purchased from sources outside of Texas, if it has a supply contract with the owner of a generating facility and submits a report to the registration agent concerning the fuel mix of the facility, in accordance with this section.

(5) If a REP offers multiple electricity products that differ with regard to renewable energy content the REP:

(A) may apply any supply contract to the calculation of any product EFL as long as the sum of MWh applied does not exceed the MWh acquired under the contract; and

(B) may apply any number of RECs to the calculation of any product EFL as long as:

(i) the number of RECs applied to all product EFLs is consistent with the number of RECs the retailer has retired with the REC Trading Program Administrator; and

(ii) the number of RECs applied to each product EFL results in a renewable energy content for each product that is equal to or greater than a benchmark to be calculated from data maintained by the REC Trading Program Administrator. The benchmark shall be defined on an annual basis as:

SRR / TS,
where

SRR = the statewide REC requirement, in MWh, as calculated by the REC Trading Program Administrator for the compliance period coinciding with the EFL, and

TS = total MWh sales for all REPs to Texas customers during the compliance period coinciding with the EFL.

(6) Any REP may anticipate the renewable content of a new product. The EFL shall state that the renewable content is an estimate that will be verified.

(g) **Fuel Mix for Renewable Energy.**

(1) The fuel mix percentage for renewable energy shall be disclosed on the EFL for the product pursuant to §25.475 of this title. The percentage used shall be rounded to the nearest whole number.

(2) **Renewable energy claims.** A REP may authenticate its sales of renewable energy by requesting that the program administrator of the renewable energy credits trading program established pursuant to §25.173(d) of this title retire a renewable energy credit for each megawatt-hour of renewable energy sold to its customers.

(h) **Annual update.** Each REP shall update its EFL for each of its currently offered products or products offered during the preceding calendar year no later than July 1 of each year, so that the EFL displays the renewable energy percentages determined pursuant to this section and reported to the registration agent for that product for generation purchased during the preceding calendar year.

(i) **Compliance and enforcement.**

(1) Upon request from the commission staff, a REP shall provide a detailed explanation or accounting of the means by which it has authenticated any renewable or "green" energy claims in an EFL or any information used for marketing a product.

(2) The commission shall coordinate its enforcement efforts regarding the prosecution of fraudulent, misleading, deceptive, and anticompetitive business practices with the Office of the Attorney General, Consumer Protection Division in order to ensure consistent treatment of specific alleged violations.

§25.477. Refusal of Electric Service.

(a) **Acceptable reasons to refuse electric service**. A retail electric provider (REP) may refuse to provide electric service to an applicant or customer for one or more of the reasons specified in this subsection:

(1) **Customer's or applicant's inadequate facilities**. The customer's or applicant's installation or equipment is known to be hazardous or of such character that satisfactory service cannot be given, or the customer's or applicant's facilities do not comply with all applicable state and municipal regulations.

(2) **Use of prohibited equipment or attachments**. The customer or applicant fails to comply with the transmission and distribution utility's, municipally owned utility's, or electric cooperative's tariff pertaining to operation of nonstandard equipment or unauthorized attachments that interfere with the service of others.

(3) **Intent to deceive.** The applicant applies for service at a location where another customer received, or continues to receive, service and the REP can reasonably demonstrate that the change of account holder and billing name is made to avoid or evade payment of a bill owed to the REP.

(4) **For indebtedness.** The applicant or customer owes a bona fide debt to the REP for electric service. An affiliated REP or provider of last resort (POLR) shall offer the applicant or customer an opportunity to pay the outstanding debt to receive service. In the event the applicant's or customer's indebtedness is in dispute, the applicant or customer shall be provided service upon paying the undisputed debt amount and a deposit pursuant to §25.478 of this title (relating to Credit Requirements and Deposits).

(5) **Failure to pay guarantee.** An applicant or customer has acted as a guarantor for another applicant or customer and failed to pay the guaranteed amount, where such guarantee was made in writing and was a condition of service.

(6) **Failure to comply with credit requirements.** The applicant or customer fails to comply with the credit and deposit requirements set forth in §25.478 of this title.

(7) **Other acceptable reasons to refuse electric service.** In addition to the reasons specified in paragraphs (1) – (6) of this subsection, a REP other than the affiliated REP or POLR may refuse to provide electric service to an applicant or customer for any other reason that is not otherwise discriminatory pursuant to §25.471(c) of this title (relating to General Provisions of Customer Protection Rules).

(b) **Insufficient grounds for refusal to serve.** The following reasons are not sufficient cause for refusal of service to an applicant or customer by a REP:

(1) delinquency in payment for electric service by a previous occupant of the premises to be served;

(2) failure to pay for any charge that is not related to electric service, including a competitive energy service, merchandise, or other services that are optional and are not included in electric service;

(3) failure to pay a bill that includes more than the allowed six months of underbilling, unless the underbilling is the result of theft of service; and

(4) failure to pay the unpaid bill of another customer for usage incurred at the same address, except where the REP has reasonable and specific grounds to believe that the applicant or customer that currently receives service has applied for service to avoid or evade payment of a bill issued to a current occupant of the same address.

(c) **Disclosure upon refusal of service.**

(1) A REP that denies electric service to an applicant or customer shall inform the applicant or customer of the reason for the denial. Upon the applicant's or customer's request, this disclosure shall be furnished in writing to the applicant or customer. This disclosure may be combined with any disclosures required by applicable federal or state law, such as the Equal Credit Opportunity Act (15 U.S.C. §1691(d), et seq.) or the Fair Credit Reporting Act (15 U.S.C. §1681(m), et seq.).

(2) A written disclosure is not required when the REP notifies the applicant or customer verbally that the applicant's or customer's premise is not located in a geographic area served by REP, does not have the type of usage characteristics served by the REP, or is not part of a customer class served by the REP.

(3) Specifically, the REP shall inform the applicant or customer:

(A) of the specific reasons for the refusal of service;

(B) that the applicant or customer may be eligible for service if the applicant or customer remedies the reasons for refusal and complies with the REP's terms and conditions of service;

(C) that the REP cannot refuse service based on the prohibited grounds set forth in §25.471(c) of this title;

(D) that an applicant or customer who is dissatisfied may submit a complaint with the commission pursuant to §25.485 of this title (relating to Customer Access and Complaint Handling); and

(E) of the possible availability or existence of other providers and the toll-free telephone number designated by the commission to allow the applicant or customer to contact the available REPs.

(d) This section is effective June 1, 2004.

§25.478. Credit Requirements and Deposits.

(a) **Credit requirements for residential customers.** A retail electric provider (REP) may require a residential customer or applicant to establish and maintain satisfactory credit as a condition of providing service pursuant to the requirements of this section.

(1) Establishment of satisfactory credit shall not relieve any customer from complying with the requirements for payment of bills by the due date of the bill.

(2) The credit worthiness of spouses established during shared service in the 12 months prior to their divorce will be equally applied to both spouses for 12 months immediately after their divorce.

(3) A residential customer or applicant seeking to establish service with an affiliated REP or provider of last resort (POLR) can demonstrate satisfactory credit using one of the criteria listed in subparagraphs (A) through (E) of this paragraph.

(A) A residential customer or applicant may be deemed as having established satisfactory credit if the customer or applicant:

(i) has been a customer of any REP or an electric utility within the two years prior to the request for electric service;

(ii) is not delinquent in payment of any such electric service account; and

(iii) during the last 12 consecutive months of service was not late in paying a bill more than once.

(B) A residential customer or applicant may be deemed as having established satisfactory credit if the customer or applicant possesses a satisfactory credit rating obtained through a consumer reporting agency, as defined by the Federal Trade Commission.

(C) A residential customer or applicant may be deemed as having established satisfactory credit if the customer or applicant is 65 years of age or older and the customer is not currently delinquent in payment of any electric service account.

(D) A residential customer or applicant may be deemed as having established satisfactory credit if the customer or applicant has been determined to be a victim of family violence as defined in the Texas Family Code §71.004, by a family violence center as defined in Texas Human Resources Code §51.002, by treating medical personnel, by law enforcement personnel, by the Office of a Texas District Attorney or County Attorney, by the Office of the Attorney General, or by a grantee of the Texas Equal Access to Justice Foundation. This determination shall be evidenced by submission of a certification letter developed by the Texas Council on Family Violence. The certification letter may be submitted directly by use of a toll-free fax number to the affiliated REP or POLR.

(E) A residential customer or applicant seeking to establish service may be deemed as having established satisfactory credit if the customer is medically indigent. In order for a customer or applicant to be considered medically indigent, the customer or applicant must make a demonstration that the following criteria are met. Such demonstration must be made annually:

(i) the customer's or applicant's household income must be at or below 150% of the poverty guidelines as certified by a governmental entity or government funded energy assistance program provider; and

(ii) the customer or applicant or the spouse of the customer or applicant must have been certified by that person's physician as being unable to perform three or more activities of daily living as defined in 22 TAC §224.4, or the customer's or applicant's monthly out-of-pocket medical expenses must exceed 20% of the household's gross income. For the purposes of this subsection, the term "physician" shall mean any medical doctor, doctor of osteopathy, nurse practitioner, registered nurse, state-licensed social workers, state-licensed physical and occupational therapists, and an employee of an agency certified to provide home health services pursuant to 42 U.S.C. §1395 *et seq*.

(4) A residential customer or applicant seeking to establish service with a REP other than an affiliated REP or POLR can demonstrate satisfactory credit using one of the criteria listed in subparagraphs (A) through (B) of this paragraph. Notice of these options for customers or applicants shall be included in any written or oral notice to a customer or applicant when a deposit is requested. A REP other than an affiliated REP or POLR may establish additional methods by which a customer or applicant not meeting the criteria of subparagraphs (A) or (B) of this paragraph can demonstrate satisfactory credit, so long as such criteria are not discriminatory pursuant to §25.471(c) of this title (relating to General Provisions of Customer Protection Rules).

(A) The residential customer or applicant is 65 years of age or older and the customer is not currently delinquent in payment of any electric service account.

(B) The customer or applicant has been determined to be a victim of family violence as defined in the Texas Family Code §71.004, by a family violence center as defined in Texas Human Resources Code §51.002, by treating medical personnel, by law enforcement personnel, by the Office of a Texas District Attorney or County Attorney, by the Office of the Attorney General, or by a grantee of the Texas Equal Access to Justice Foundation. This determination shall be evidenced by submission of a certification letter developed by the Texas Council on Family Violence. The certification letter may be submitted directly by use of a toll-free fax number to the REP.

(5) The REP may obtain payment history information from any REP that has served the applicant in the previous two years or from a consumer reporting agency, as defined by the Federal Trade Commission. The REP shall obtain the customer's or applicant's authorization prior to obtaining such information from the customer's or applicant's prior REP. A REP shall maintain payment history information for two years after a customer's electric service has been terminated or disconnected in order to be able to provide credit history information at the request of the former customer.

(b) **Credit requirements for non-residential customers**. A REP may establish nondiscriminatory criteria pursuant to §25.471(c) of this title to evaluate the credit requirements for a non-residential customer or applicant and apply those criteria in a nondiscriminatory manner. If satisfactory credit cannot be demonstrated by the non-residential customer or applicant using the criteria established by the REP, the customer may be required to pay an initial or additional deposit. No such deposit shall be required if the customer or applicant is a governmental entity.

(c) **Initial deposits for applicants and existing customers.**

(1) If satisfactory credit cannot be demonstrated by a residential applicant, a REP may require the applicant to pay a deposit prior to receiving service.

(2) An affiliated REP or POLR shall offer a residential customer or applicant who is required to pay an initial deposit the option of providing a written letter of guarantee pursuant to subsection (i) of this section, instead of paying a cash deposit.

(3) A REP shall not require an initial deposit from an existing customer unless the customer was late paying a bill more than once during the last 12 months of service or had service terminated or disconnected for nonpayment during the last 12 months of service. The customer may be required to pay this initial deposit within ten days after issuance of a written disconnection notice that requests such deposit. The disconnection notice may be combined with or issued concurrently with the request for deposit. The disconnection notice shall comply with the requirements in §25.483(m) of this title (relating to Disconnection of Service).

(d) **Additional deposits by existing customers.**

(1) A REP may request an additional deposit from an existing customer if:

(A) the average of the customer's actual billings for the last 12 months are at least twice the amount of the original average of the estimated annual billings; and

(B) a termination or disconnection notice has been issued or the account disconnected within the previous 12 months.

(2) A REP may require the customer to pay an additional deposit within ten days after the REP has requested the additional deposit.

(3) A REP may disconnect service if the additional deposit is not paid within ten days of the request, provided a written disconnection notice has been issued to the customer. A disconnection notice may be combined with or issued concurrently with the written request for the additional deposit. The disconnection notice shall comply with the requirements in §25.483(m) of this title.

(e) **Amount of deposit.**

(1) The total of all deposits, initial and additional, required by a REP from any residential customer or applicant:

(A) shall not exceed an amount equivalent to the greater of:

(i) one-fifth of the customer's estimated annual billing; or

(ii) the sum of the estimated billings for the next two months.

(B) A REP may base the estimated annual billing for initial deposits for applicants on a reasonable estimate of average usage for the customer class. If a REP requests additional or initial deposits from existing customers, the REP shall base the estimated annual billing on the customer's actual historical usage, to the extent that the historical usage is available. After 12 months of service with a REP, a customer may request that a REP recalculate the required deposit based on actual historical usage of the customer.

(2) For the purpose of determining the amount of the deposit, the estimated billings shall include only charges for electric service that are disclosed in the REP's terms of service document provided to the customer or applicant.

(f) **Interest on deposits.** A REP that requires a deposit pursuant to this section shall pay interest on that deposit at an annual rate at least equal to that set by the commission on or before December 1 of the preceding calendar year, pursuant to Texas Utilities Code §183.003 (relating to Rate of Interest). If a deposit is refunded within 30 days of the date of deposit, no interest payment is required. If the REP keeps the deposit more than 30 days, payment of interest shall be made from the date of deposit.

(1) Payment of the interest to the customer shall be made annually, if requested by the customer, or at the time the deposit is returned or credited to the customer's account.

(2) The deposit shall cease to draw interest on the date it is returned or credited to the customer's account.

(g) **Notification to customers.** When a REP requires a customer to pay a deposit, the REP shall provide the customer written information about the provider's deposit policy, the customer's right to post a guarantee in lieu of a cash deposit if applicable, how a customer may be refunded a deposit, and the circumstances under which a provider may increase a deposit. These disclosures shall be included either in the Your Rights as a Customer disclosure or the REP's terms of service document.

(h) **Records of deposits.**

(1) A REP that collects a deposit shall keep records to show:

(A) the name and address of each depositor;

(B) the amount and date of the deposit; and

(C) each transaction concerning the deposit.

(2) A REP that collects a deposit shall issue a receipt of deposit to each customer or applicant paying a deposit or reflect the deposit on the customer's bill statement. A REP shall provide means for a depositor to establish a claim if the receipt is lost.

(3) A REP shall maintain a record of each unclaimed deposit for at least four years.

(4) A REP shall make a reasonable effort to return unclaimed deposits.

(i) **Guarantees of residential customer accounts.** A guarantee agreement in lieu of a cash deposit issued by any REP, if applicable, shall conform to the following requirements:

(1) A guarantee agreement between a REP and a guarantor shall be in writing and shall be for no more than the amount of deposit the provider would require on the customer's account pursuant to subsection (e) of this section. The amount of the guarantee shall be clearly indicated in the signed agreement. The REP may require, as a condition of the continuation of the guarantee agreement, that the guarantor remain a customer of the REP, have no past due balance, and have no more than one late payment in a 12-month period during the term of the guarantee agreement.

(2) The guarantee shall be voided and returned to the guarantor according to the provisions of subsection (j) of this section.

(3) Upon default by a residential customer, the guarantor of that customer's account shall be responsible for the unpaid balance of the account only up to the amount agreed to in the written agreement.

(4) If the guarantor ceases to be a customer of the REP or has more than one late payment in a 12-month period during the term of the guarantee agreement, the provider may treat the guarantee agreement as in default and demand a cash deposit from the residential customer as a condition of continuing service.

(5) The REP shall provide written notification to the guarantor of the customer's default, the amount owed by the guarantor, and the due date for the amount owed.

(A) The REP shall allow the guarantor 16 days from the date of notification to pay the amount owed on the defaulted account. If the sixteenth day falls on a holiday or weekend, the due date shall be the next business day.

(B) The REP may transfer the amount owed on the defaulted account to the guarantor's own electric service bill provided the guaranteed amount owed is identified separately on the bill as required by §25.479 of this title (relating to Issuance and Format of Bills).

(6) The REP may initiate disconnection for nonpayment of the guaranteed amount only if the disconnection of service was disclosed in the written guarantee agreement, and only after proper notice as described by paragraph (5) of this subsection or §25.483 of this title.

(j) **Refunding deposits and voiding letters of guarantee.**

(1) A deposit held by a REP shall be refunded when the customer has paid bills for service for 12 consecutive residential billings or for 24 consecutive non-residential billings without having any late payments. A REP may refund the deposit to a customer via a bill credit. REPs shall comply with this provision as soon as practicable, but no later than August 31, 2004.

(2) Once the REP is no longer the REP of record for a customer or if service is not established with the REP, the REP shall either transfer the deposit plus accrued interest to the customer's new REP or promptly refund the deposit plus accrued interest to the customer, as agreed upon by the customer and both REPs. The REP may subtract from the amount refunded any amounts still owed by the customer to the REP. If the REP obtained a guarantee, such guarantee shall be cancelled to the extent that it is not needed to satisfy any outstanding balance owed by the customer. Alternatively, the REP may provide the guarantor with written documentation that the contract has been cancelled to the extent that the guarantee is not needed to satisfy any outstanding balance owed by the customer.

(3) If a customer's or applicant's service is not connected, or is disconnected, or the service is terminated by the customer, the REP shall promptly void and return to the guarantor all letters of guarantee on the account or provide written documentation that the guarantee agreement has been voided, or refund the customer's or applicant's deposit plus accrued interest on the balance, if any, in excess of the unpaid bills for service furnished. Similarly, if the guarantor's service is not

connected, or is disconnected, or the service is terminated by the customer, the REP shall promptly void and return to the guarantor all letters of guarantee or provide written documentation that the guarantees have been voided. This provision does not apply when the customer or guarantor moves or changes the address where service is provided, as long as the customer or guarantor remains a customer of the REP.

(4) A REP shall terminate a guarantee agreement when the customer has paid its bills for 12 consecutive months without service being disconnected for nonpayment and without having more than two delinquent payments.

(k) **Re-establishment of credit.** A customer or applicant who previously has been a customer of the REP and whose service has been terminated or disconnected for nonpayment of bills or theft of service by that customer (meter tampering or bypassing of meter) may be required, before service is reinstated, to pay all amounts due to the REP or execute a deferred payment agreement, if offered, and reestablish credit.

(l) **Upon sale or transfer of company.** Upon the sale or transfer of a REP or the designation of an alternative POLR for the customer's electric service, the seller or transferee shall provide the legal successor to the original provider all deposit records.

§25.479. Issuance and Format of Bills.

(a) **Application.** This section applies, beginning April 1, 2010, to a retail electric provider (REP) that is responsible for issuing electric service bills to retail customers, unless the REP is issuing a consolidated bill (both energy services and transmission and distribution services) on behalf of an electric cooperative or municipally owned utility. This section does not apply to a municipally owned utility or electric cooperative issuing bills to its customers in its own service territory.

(b) **Frequency and delivery of bills.**

(1) A REP shall issue a bill monthly to each customer, unless service is provided for a period of less than one month. A REP may issue a bill less frequently than monthly if both the customer and the REP agree to such an arrangement.

(2) Bills shall be issued no later than 30 days after the REP receives the usage data and any related invoices for non-bypassable charges, unless validation of the usage data and invoice received from a transmission and distribution utility by the REP or other efforts to determine the accuracy of usage data or invoices delay billing by a REP past 30 days. The number of days to issue a bill shall be extended beyond 30 days to the extent necessary to support agreements between REPs and customers for less frequent billing, as provided in paragraph (1) of this subsection or for consolidated billing.

(3) A REP shall issue bills to residential customers in writing and delivered via the United States Postal Service. REPs may provide bills to a customer electronically in lieu of written mailings if both the customer and the REP agree to such an arrangement. An affiliated REP or a provider of last resort shall not require a customer to agree to such an arrangement as a condition of receiving electric service.

(4) A REP shall not charge a customer a fee for issuing a standard bill, which is a bill delivered via U.S. mail that complies with the requirements of this section. The customer may be charged a fee or given a discount for non-standard billing in accordance with the terms of service document.

(c) **Bill content.**

(1) Each customer's bill shall include the following information:

(A) The certified name and address of the REP and the number of the license issued to the REP by the commission;

(B) A toll-free telephone number, in bold-face type, which the customer can call during specified hours for inquiries and to make complaints to the REP about the bill;

(C) A toll-free telephone number that the customer may call 24 hours a day, seven days a week, to report power outages and concerns about the safety of the electric power system;

(D) The service address, electric service identifier (ESI), and account number of the customer;

(E) The service period for which the bill is rendered;

(F) The date on which the bill was issued;

(G) The payment due date of the bill and, if different, the date by which payment from the customer must be received by the REP to avoid a late charge or other collection action;

(H) The current charges for electric service as disclosed in the customer's terms of service document, including applicable taxes and fees labeled "current charges." If the customer is on a level or average payment plan, the level or average payment due shall be clearly shown in addition to the current charges;

(I) A calculation of the average unit price for electric service for the current billing period, labeled, "The average price you paid for electric service this month." The calculation of the average price for electric service shall reflect the total of all fixed and variable recurring charges, but not include state and local sales taxes, reimbursement for the state miscellaneous gross receipts tax, and any nonrecurring charges or credits, divided by the kilowatt-hour consumption, and shall be expressed as a cents per kilowatt-hour amount rounded to the nearest one-tenth of one cent.

(J) The identification and itemization of charges other than for electric service as disclosed in the customer's terms of service document;

(K) The itemization and amount of any non-recurring charge, including late fees, returned check fees, restoration of service fees, or other fees disclosed in the REP's terms of service document provided to the customer;

(L) The balances from the preceding bill, payments made by the customer since the preceding bill, and the amount the customer is required to pay by the due date, labeled "amount due;"

(M) A notice that the customer has the opportunity to voluntarily donate money to the bill payment assistance program, pursuant to §25.480(g)(2) of this title (relating to Bill Payment and Adjustments);

(N) If available to the REP on a standard electronic transaction, if the bill is based on kilowatt-hour (kWh) usage, the following information:

(i) the meter reading at the beginning of the period for which the customer is being billed, labeled "previous meter read," and the meter reading at the end of the period for which the customer is being billed, labeled "current meter read," and the dates of such readings;

(ii) the kind and number of units measured, including kWh, actual kilowatts (kW), or kilovolt ampere (kVa);

(iii) if applicable, billed kW or kVa;

(iv) whether the bill was issued based on estimated usage; and

(v) any conversions from meter reading units to billing units, or any other calculations to determine billing units from recording or other devices, or any other factors used in determining the bill, unless the customer is provided conversion charts;

(O) Any amount owed under a written guarantee agreement, provided the guarantor was previously notified in writing by the REP of an obligation on a guarantee as required by §25.478 of this title (relating to Credit Requirements and Deposits);

(P) A conspicuous notice of any services or products being provided to the customer that have been added since the previous bill;

(Q) Notification of any changes in the customer's prices or charges due to the operation of a variable rate feature previously disclosed by the REP in the customer's terms of service document;

(R) The notice required by §25.481(d) of this title (relating to Unauthorized Charges); and

(S) For residential customers, on the first page of the bill in at least 12-point font the phrase, "for more information about residential electric service please visit www.powertochoose.com."

(2) If a REP separately identifies a charge defined by one of the terms in this paragraph on the customer's bill, then the term in this paragraph must be used to identify that charge, and such term and its definition shall be easily located on the REP's website and available to a customer free of charge upon request. Nothing in this paragraph precludes a REP from aggregating transmission and distribution utility (TDU) or REP charges. For any TDU charge(s) listed in this paragraph, the amount billed by the REP shall not exceed the amount of the TDU tariff charge(s). The label for any TDU charge(s) may also identify the TDU that issued the charge(s). A REP may use a different term than a defined term by adding or deleting a suffix, by adding the word "total" to a defined term, where appropriate, changing the use of lower-case or capital letters or punctuation, or using the acceptable abbreviation specified in this paragraph for a defined term. If an abbreviation other than the acceptable abbreviation is used for the term, then the term must also be identified on the customer's bill.

(A) Advanced metering charge -- A charge assessed to recover a TDU's charges for Advanced Metering Systems, to the extent that they are not recovered in a TDU's standard metering charge. Acceptable abbreviation: Advanced Meter.

(B) Competition Transition Charge -- A charge assessed to recover a TDU's charges for nonsecuritized costs associated with the transition to competition. Acceptable abbreviation: Competition Transition.

(C) Energy Efficiency Cost Recovery Factor -- A charge assessed to recover a TDU's costs for energy efficiency programs, to the extent that the TDU charge is a separate charge exclusively for that purpose that is approved by the Public Utility Commission. Acceptable abbreviation: Energy Efficiency.

(D) Late Payment Penalty -- A charge assessed for late payment in accordance with Public Utility Commission rules.

(E) Meter Charge -- A charge assessed to recover a TDU's charges for metering a customer's consumption, to the extent that the TDU charge is a separate charge exclusively for that purpose that is approved by the Public Utility Commission.

(F) Miscellaneous Gross Receipts Tax Reimbursement -- A fee assessed to recover he miscellaneous gross receipts tax imposed on retail electric providers operating in an incorporated city or town having a population of more than 1,000. Acceptable abbreviation: Gross Receipts Reimb.

(G) Nuclear Decommissioning Fee -- A charge assessed to recover a TDU's charges for decommissioning of nuclear generating sites. Acceptable abbreviation: Nuclear Decommission.

(H) PUC Assessment -- A fee assessed to recover the statutory fee for administering the Public Utility Regulatory Act.

(I) Sales tax -- Sales tax collected by authorized taxing authorities, such as the state, cities and special purpose districts.

(J) TDU Delivery Charges -- The total amounts assessed by a TDU for the delivery of electricity to a customer over poles and wires and other TDU facilities not including discretionary charges.

(K) Transmission Distribution Surcharges -- One or more TDU surcharge(s) on a customer's bill in any combination. Surcharges include charges billed as tariff riders by the TDU. Acceptable abbreviation: TDU Surcharges.

(L) Transition Charge -- A charge assessed to recover a TDU's charges for securitized costs associated with the transition to competition.

(3) If the REP includes any of the following terms in its bills, the term shall be applied in a manner consistent with the definitions, and such term and its definition shall be easily located on the REP's website and available to a customer free of charge upon request:

(A) Base Charge -- A charge assessed during each billing cycle without regard to the customer's demand or energy consumption.

(B) Demand Charge -- A charge based on the rate at which electric energy is delivered to or by a system at a given instant, or averaged over a designated period, during the billing cycle.

(C) Energy Charge -- A charge based on the electric energy (kWh) consumed.

(4) A REP shall provide an itemization of charges, including non-bypassable charges, to the customer upon the customer's request and, to the extent that the charges are consistent with the terms set out in paragraph (2), of this subsection, the terms shall be used in the itemization.

(5) A customer's electric bill shall not contain charges for electric service from a service provider other than the customer's designated REP.

(6) A REP shall include on each residential and small commercial billing statement the date, as provided for in §25.475(c)(3)(B) of this title (relating to General Retail Electric Provider

Requirements and Information Disclosure to Residential and Small Commercial Customers) that a fixed rate product will expire.

(7) To the extent that a REP uses the concepts identified in this paragraph in a customer's bill, it shall use the term set out in this paragraph, and the definitions in this paragraph shall be easily located on the REP's website. A REP may not use a different term for a concept that is defined in this paragraph.

(A) kW -- Kilowatt, the standard unit for measuring electricity demand, equal to 1,000 watts;

(B) kWh -- Kilowatt-hour, the standard unit for measuring electricity energy consumption, equal to 1,000 watt-hours; and

(8) Notice of contract expiration may be provided in a bill in accordance with §25.475 of this title.

(d) **Public service notices.** A REP shall, as required by the commission after reasonable notice, provide brief public service notices to its customers. The REP shall provide these public service notices to its customers on its billing statements, as a separate document issued with its bill, by electronic communication, or by other acceptable mass communication methods, as approved by the commission.

(e) **Estimated bills.** If a REP is unable to issue a bill based on actual meter reading due to the failure of the TDU, the registration agent, municipally owned utility or electric cooperative to obtain or transmit a meter reading or an invoice for non-bypassable charges to the REP on a timely basis, the REP may issue a bill based on the customer's estimated usage and inform the customer of the reason for the issuance of the estimated bill.

(f) **Non-recurring charges.** A REP may pass through to its customers all applicable non-recurring charges billed to the REP by a TDU, municipally owned utility, or electric cooperative as a result of establishing, switching, disconnecting, reconnecting, or maintaining service to an applicant or customer. In the event of a meter test, the TDU, municipally owned utility, electric cooperative, and REP shall comply with the requirements of §25.124 of this title (relating to Meter Testing) or with the requirements of the tariffs of a TDU, municipally owned utility, or electric cooperative, as applicable. The TDU, municipally owned utility, or electric cooperative shall maintain a record of all meter tests performed at the request of a REP or a REP's customers.

(g) **Record retention.** A REP shall maintain monthly billing and payment records for each account for at least 24 months after the date the bill is mailed. The billing records shall contain sufficient data to reconstruct a customer's billing for a given period. A copy of a customer's billing records may be obtained by that customer on request, and may be obtained once per 12-month period, at no charge.

(h) **Transfer of delinquent balances or credits.** If the customer has an outstanding balance or credit owed to the customer's current REP that is due from a previous account in the same customer class, then the customer's current REP may transfer that balance to the customer's current account. The delinquent balance and specific account or address shall be identified as such on the bill. There shall be no balance transfers between REPs, other than transfer of a deposit, as specified in §25.478(j)(2) of this title.

§25.480. Bill Payment and Adjustments.

(a) **Application.** This section applies to a retail electric provider (REP) that is responsible for issuing electric service bills to retail customers, unless the REP is issuing a consolidated bill (both energy services and transmission and distribution services) on behalf of an electric cooperative or municipally owned utility. In addition, this section applies to a transmission and distribution utility (TDU) where specifically stated. This section does not apply to a municipally owned utility or electric cooperative issuing bills to its customers in its own service territory.

(b) **Bill due date**. A REP shall state a payment due date on the bill which shall not be less than 16 days after issuance. A bill is considered to be issued on the issuance date stated on the bill or the postmark date on the envelope, whichever is later. A payment for electric service is delinquent if not received by the REP or at the REP's authorized payment agency by the close of business on the due date. If the 16th day falls on a holiday or weekend, then the due date shall be the next business day after the 16th day.

(c) **Penalty on delinquent bills for electric service.**
A REP may charge a one-time penalty not to exceed 5.0% on a delinquent bill for electric service. No such penalty shall apply to residential or small commercial customers served by the provider of last resort (POLR). The one-time penalty, not to exceed 5.0%, may not be applied to any balance to which the penalty has already been applied.

(d) **Overbilling.** If charges are found to be higher than authorized in the REP's terms and conditions for service or other applicable commission rules, then the customer's bill shall be corrected.

- (1) The correction shall be made for the entire period of the overbilling.
- (2) If the REP corrects the overbilling within three billing cycles of the error, it need not pay interest on the amount of the correction.
- (3) If the REP does not correct the overcharge within three billing cycles of the error, it shall pay interest on the amount of the overcharge at the rate set by the commission.
  - (A) Interest on overcharges that are not adjusted by the REP within three billing cycles of the bill in error shall accrue from the date of payment by the customer.
  - (B) All interest shall be compounded monthly at the approved annual rate set by the commission.
  - (C) Interest shall not apply to leveling plans or estimated billings.
- (4) If the REP rebills for a prior billing cycle, the adjustments shall be identified by account and billing date or service period.

(e) **Underbilling by a REP.** If charges are found to be lower than authorized by the REP's terms and conditions of service, or if the REP fails to bill the customer for service, then the customer's bill may be corrected.

- (1) The customer shall not be responsible for corrected charges billed by the REP unless such charges are billed by the REP within 180 days from the date of issuance of the bill in which the underbilling occurred The REP may backbill a customer for the amount that was underbilled beyond the timelines provided in this paragraph if:
  - (A) the underbilling is found to be the result of meter tampering by the customer; or
  - (B) the TDU bills the REP for an underbilling as a result of meter error as provided in §25.126 of this title (relating to Adjustments Due to Non-Compliant Meters and Meter Tampering in Areas Where Customer Choice Has Been Introduced).
- (2) The REP may disconnect service pursuant to §25.483 of this title (relating to Disconnection of Service) if the customer fails to pay the additional charges within a reasonable time.

(3) If the underbilling is $50 or more, the REP shall offer the customer a deferred payment plan option for the same length of time as that of the underbilling. A deferred payment plan need not be offered to a customer when the underpayment is due to theft of service.

(4) The REP shall not charge interest on underbilled amounts unless such amounts are found to be the result of theft of service (meter tampering, bypass, or diversion) by the customer. Interest on underbilled amounts shall be compounded monthly at the annual rate, as set by the commission. Interest shall accrue from the day the customer is found to have first stolen the service.

(5) If the REP adjusts the bills for a prior billing cycle, the adjustments shall be identified by account and billing date or service period.

(f) **Disputed bills.** If there is a dispute between a customer and a REP about the REP's bill for any service billed on the retail electric bill, the REP shall promptly investigate and report the results to the customer. The REP shall inform the customer of the complaint procedures of the commission pursuant to §25.485 of this title (relating to Customer Access and Complaint Handling).

(g) **Alternate payment programs or payment assistance.**

(1) **Notice required.** When a customer contacts a REP and indicates inability to pay a bill or a need for assistance with the bill payment, the REP shall inform the customer of all applicable payment options and payment assistance programs that are offered by or available from the REP, such as bill payment assistance, deferred payment plans, disconnection moratoriums for the ill, or low-income energy assistance programs, and of the eligibility requirements and procedure for applying for each.

(2) **Bill payment assistance programs.**

(A) All REPs shall implement a bill payment assistance program for residential electric customers. At a minimum, such a program shall solicit voluntary donations from customers through the retail electric bills.

(B) A REP shall obtain a commitment from an assistance agency selected to disburse bill payment assistance funds that the agency will not discriminate in the distribution of such funds to customers based on the customer's race, creed, color, national origin, ancestry, sex, marital status, lawful source of income, disability, familial status, location of customer in an economically distressed geographic area, or qualification for low-income affordability or energy efficiency services.

(3) A REP shall provide, in a project established by the commission, information about its voluntary bill payment assistance program for burned veterans. This information shall include the REP's name, the REP's certification number, and a toll free telephone number and website address where customers can obtain additional information. The commission will publish such information on the commission website.

(h) **Level and average payment plans.** A REP shall make a level or average payment plan available to its customers consistent with this subsection. A customer receiving service from a provider of last resort (POLR) may be required to select a competitive product offered by the POLR REP to receive the level or average payment plan.

(1) A REP shall make a level or average payment plan available to a customer who is not currently delinquent in payment to the REP. A customer is delinquent in payment in the following circumstances:

(A) A customer whose normal billing arrangement provides for payment after the rendition of service is delinquent if the date specified for payment of a bill has passed and the customer has not paid the full amount due.

(B) A customer whose normal billing arrangement provides for payment before the rendition of service is delinquent if the customer has a negative balance on the account for electric service.

(2) A REP shall reconcile any over- or under-payment consistent with the applicable terms of service, which shall provide for reconciliation at least every twelve months. For a customer with an average payment plan, a REP may recalculate the average consumption or average bill and adjust the customer's required minimum payment as frequently as every billing period. A REP may collect under-payments associated with a level payment plan from a customer over a period no less than the reconciliation period or upon termination of service to the customer. A REP shall credit or refund any over-payments associated with a level payment plan to the customer at each reconciliation and upon termination of service to the customer. A REP may initiate its normal collection activity if a customer fails to make a timely payment according to such a level or average payment plan. All details concerning a level or average payment program shall be disclosed in the customer's terms of service document.

(3) If the customer is delinquent in payment when the level or average payment plan is established, the REP may require the customer to pay no greater than 50% of the delinquent amount due. The REP may require the remaining delinquent amount to be paid by the customer in equal installments over at least five billing cycles unless the customer agrees to fewer installments or may include the remaining delinquent amount in the calculation of the level or average payment amount. If the REP requires installment payments, the REP shall provide the customer a copy of the deferred payment plan in writing as described in subsection (j)(5) of this section.

(4) If the amount of the deferred balance does not appear on each bill the customer receives, the REP shall inform the customer that the customer may call the REP at any time to determine the amount that must be paid to be removed from the level or average payment plan.

(5) If the customer is delinquent in payment when the level or average payment plan is established, the REP may apply a switch-hold at that time.

(6) Before the REP applies a switch-hold to a customer on a level or average payment plan, the REP shall provide orally or in writing a clear explanation of the switch-hold process to the customer, prior to the customer's agreement to the plan. The explanation shall inform the customer as follows: "If you enter into this plan concerning your past due amount, we will put a switch-hold on your account. A switch-hold means that you will not be able to buy electricity from other companies until you pay the total deferred balance. If we put a switch-hold on your account, it will be removed after your deferred balance is paid and processed. While a switch-hold applies, if you are disconnected for not paying, you will need to pay {us or company name}, to get your electricity turned back on."

(7) If the customer is not delinquent in payment when the level or average payment plan is established, a switch-hold shall not be applied unless the plan is established pursuant to subsection (j)(2)(B)(ii) of this section.

(8) The REP, through a standard market process, shall submit a request to remove the switch-hold, pursuant to subsection (m) of this section, when the customer satisfies either subparagraph (A) or (B) of this paragraph, whichever occurs earlier. On the date the REP submits the request to remove the switch-hold, the REP shall notify or send notice to the customer that the customer has satisfied the obligation to pay any deferred balance owed and the removal of the switch-hold is being processed.

(A) The customer's deferred balance, including any deferred delinquent amount described in paragraph (4) of this subsection, is either zero or in an over-payment status.

(B) The customer satisfies the terms of any deferred delinquent amount described in paragraph (4) of this subsection and has paid bills for 12 consecutive billings without having been disconnected and without having more than one late payment.

(i) **Payment arrangements.** A payment arrangement is any agreement between the REP and a customer that allows a customer to pay the outstanding bill after its due date, but before the due date of the next bill. If the REP issues a disconnection notice before a payment arrangement was made, that disconnection should be suspended until after the due date for the payment arrangement. If a customer does not fulfill the terms of the payment arrangement, service may be disconnected after the later of the due date for the payment arrangement or the disconnection date indicated in the notice, without issuing an additional disconnection notice.

(j) **Deferred payment plans and other alternate payment arrangements.**

(1) A deferred payment plan is an agreement between the REP and a customer that allows a customer to pay an outstanding balance in installments that extend beyond the due date of the current bill. A deferred payment plan may be established in person, by telephone, or online, but all deferred payment plans shall be confirmed in writing by the REP in accordance with paragraph (5) of this subsection. Before the REP applies a switch-hold to a customer on a deferred payment plan, the REP shall provide a clear explanation of the switch-hold process to the customer. The explanation shall inform the customer as follows: "If you enter into this plan concerning your past due amount, we will put a switch-hold on your account. A switch-hold means that you will not be able to buy electricity from other companies until you pay the total deferred balance. If we put a switch-hold on your account, it will be removed after your deferred balance is paid and processed. While a switch-hold applies, if you are disconnected for not paying, you will need to pay {us or company name}, to get your electricity turned back on."

(A) A REP shall offer a deferred payment plan to customers, upon request, for bills that become due during an extreme weather emergency, pursuant to §25.483(j) of this title.

(B) As directed by the commission, during a state of disaster declared by the governor pursuant to Texas Government Code §418.014, a REP shall offer a deferred payment plan to customers, upon request, in the area covered by the declaration.

(C) A REP shall offer a deferred payment plan to a customer who has been underbilled, pursuant to subsection (e) of this section.

(2) A REP shall make a payment plan available, upon request, to a residential customer that meets the requirements of subparagraph (A) of this paragraph for a bill that becomes due in July, August, or September. A REP shall make a payment plan available, upon request, to a residential customer that meets the requirements of subparagraph (A) of this paragraph for a bill that becomes due in January or February if in the prior month a TDU notified the commission pursuant to §25.483(j) of this title of an extreme weather emergency for the residential customer's county in the TDU service area for at least five consecutive days during the month. A REP is not required to offer a payment plan to a customer pursuant to this paragraph if the customer is on an existing deferred, level, or average payment plan.

(A) The following residential customers are eligible for a payment plan under this paragraph:

(i) customers designated as Critical Care Residential Customers or Chronic Condition Residential Customers under §25.497 of this title (relating to Critical Load Industrial Customers, Critical Load Public Safety Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers); or

(ii) customers who have expressed an inability to pay unless the customer:

(I) has been disconnected during the preceding 12 months;

(II) has submitted more than two payments during the preceding 12 months that were found to have insufficient funds available; or

(III) has received service from the REP for less than three months, and the customer lacks:

(-a-) sufficient credit; or

(-b-) a satisfactory history of payment for electric service from a previous REP or utility.

(B) The REP shall make available, at the customer's option, the plans described in clauses (i) and (ii) of this subparagraph.

(i) A deferred payment plan with the initial payment amount no greater than 50% of the amount due. The deferred amount shall be paid by the customer in equal installments over at least five billing cycles unless the customer agrees to fewer installments.

(ii) A level or average payment plan instead of requiring the balance due to be paid. The level or average payment plan shall be offered subject to the requirements of subsection (h) of this section.

(C) The REP shall not seek an additional deposit as a result of a customer's entering into a deferred payment plan under this paragraph.

(3) A REP shall not refuse customer participation in a deferred payment plan on any basis set forth in §25.471(c) of this title (relating to General Provisions of Customer Protection Rules).

(4) A REP may voluntarily offer a deferred payment plan to customers who have expressed an inability to pay.

(5) A copy of the deferred payment plan shall be provided to the customer and:

(A) shall include a statement, in a clear and conspicuous type, that states "If you are not satisfied with this agreement, or if the agreement was made by telephone and you feel this does not reflect your understanding of that agreement, contact (insert name and contact number of REP).";

(B) if a switch-hold will apply, shall include a statement, in a clear and conspicuous type, that states "By entering into this agreement, you understand that {company name} will put a switch-hold on your account. A switch-hold means that you will not be able to buy electricity from other companies until you pay this past due amount. The switch-hold will be removed after your final payment on this past due amount is processed. While a switch-hold applies, if you are disconnected for not paying, you will need to pay {us or company name}, to get your electricity turned back on.";

(C) where the customer and the REP's representative or agent meets in person, the representative shall read the statements in subparagraph (A) and, if applicable, subparagraph (B) of this paragraph to the customer;

(D) may include the one-time penalty in accordance with subsection (c) of this section but shall not include a finance charge;

(E) shall state the length of time covered by the plan;

(F) shall state the total amount to be paid under the plan;

(G) shall state the specific amount of each installment;

(H) shall state whether the amount of the deferred balance will appear on each bill the customer receives and that the customer may call the REP at any time to determine the amount that must be paid to satisfy the terms of the deferred payment plan; and

(I) shall state whether there may be a disconnection of service if the customer does not fulfill the terms of the deferred payment plan, and shall state the terms for disconnection.

(6) A REP may pursue disconnection of service if a customer does not meet the terms of a deferred payment plan. However, service shall not be disconnected until appropriate notice has been issued, pursuant to §25.483 of this title, notifying the customer that the customer has not met the terms of the plan. The requirements of paragraph (2) of this subsection shall not apply with respect to a customer who has defaulted on a deferred payment plan.

(7) A REP may apply a switch-hold while the customer is on a deferred payment plan.

(8) The REP, through a standard market process, shall submit a request to remove the switch-hold, pursuant to subsection (m) of this section, after the customer's payment of the deferred balance owed to the REP. On the day the REP submits the request to remove the switch-hold, the REP shall notify or send notice to the customer that the customer has satisfied the obligation to pay any deferred balance owed and the removal of the switch-hold is being processed.

(k) **Allocation of partial payments.** A REP shall allocate a partial payment by the customer first to the oldest balance due for electric service, followed by the current amount due for electric service. When there is no longer a balance for electric service, payment may be applied to non-electric services billed by the REP. Electric service shall not be disconnected for non-payment of non-electric services.

(l) **Switch-hold.**

(1) A REP may request that the TDU place a switch-hold on an ESI ID to the extent allowed by subsection (h) or (j) of this section, which shall prevent a switch transaction from being completed for the ESI ID and shall prevent a move-in transaction from being completed pending documentation that the applicant for electric service is a new occupant not associated with the customer for which the switch-hold was imposed. If the REP exercises its right to disconnect service for non-payment pursuant to §25.483 of this title, the switch-hold shall continue to remain in place. The TDU shall create and maintain a secure list of ESI IDs with switch-holds that REPs may access. The list shall not include any customer information other than the ESI ID and date the switch-hold was placed. The list shall be updated daily, and made available through a secure means by the TDU. The TDU may provide this list in a secure format through the web portal developed as part of its AMS deployment.

(A) The REP via a standard market process may request a switch-hold.

(B) The REP shall submit a request to remove the switch-hold as required by subsections (h)(9) and (j)(8) of this section.

(C) When the REP of record issues a move-out request for the flagged ESI ID, the REP of record's relationship with the ESI ID is terminated and the switch-hold shall be removed.

(D) At the time of a mass transition, the TDU shall remove the switch-hold flag for any ESI ID that is transitioned to a provider of last resort (POLR) provider.

(E) When the applicant for electric service is shown to be a new occupant not associated with the customer for which the switch-hold was imposed using the switch-hold process described in §25.126 of this title, the switch-hold flag shall be removed.

(F) For a move-in transaction indicating that the ESI ID is subject to a continuous service agreement, the TDU shall remove any switch-hold on that ESI ID and complete the move-in.

(2) In the first TX SET release after January 1, 2011, market transactions shall be developed that support the following requirements.

(A) REPs may request a switch-hold as allowed by subsection (h) or (j) of this section.

(B) TDUs shall provide indication of which ESI IDs have switch-holds so that during a move-in enrollment a REP can identify whether a switch-hold applies and that specific documentation must be submitted to have the switch-hold removed.

(C) A move-in subject to a switch-hold can be submitted for processing when the customer initially requests the move-in and such transaction will be held in the system for final processing depending on the approval or rejection of the move-in documentation. The TDU shall notify the submitting REP that there is a switch-hold on the ESI ID.

(3) The requirements of §25.475 of this title (relating to General Retail Electric Provider Requirements and Information Disclosures to Residential and Small Commercial Customers) shall continue to apply while a customer is subject to a switch-hold. The notice required by §25.475(e) of this title shall include a statement reminding the customer that if a switch-hold is in effect, the balance deferred must be paid in full before the customer will be able to change to a new provider.

(4) A customer who is subject to a switch-hold shall not be charged any separate fees for a switch-hold or any customer service or administrative fees related to the switch-hold.

(5) A REP shall not discriminate against any customer that is on a switch-hold in the provision of services or pricing of products. A customer on a switch-hold shall be eligible for all services and products generally available to the REPs other customers.

(6) If a REP applies a switch-hold to a customer account and the customer's contract expires while under the switch-hold, the REP shall provide notice of the contract expiration as required by §25.475 of this title. Unless a customer affirmatively chooses a different product with the REP, a customer whose term product expires while the customer is subject to a switch-hold shall be moved to the lowest priced month-to-month product currently offered by the REP to new applicants, or, if the REP does not offer month-to-month products to new applicants, shall be served on a month-to-month basis at the price equivalent to the lowest price of the shortest term fixed product currently offered by the REP to new applicants. Otherwise, the REP shall request the removal of the switch-hold in compliance with subsection (m) of this section. The offers shall include those made on www.powertochoose.com. If the customer does not affirmatively choose a product, the customer shall not be required by the REP to enter into another contract term so long as the switch-hold remains on the customer account and no early termination fees shall be applied to the customer's account.

(m) **Placement and Removal of Switch-Holds.**

(1) A REP may request a switch-hold only as allowed under this section.

(2) A REP shall be responsible for requesting that the TDU remove a switch-hold after the customer's obligation to the REP related to the switch-hold is satisfied. If a customer's obligation to the REP is satisfied by 10:00 p.m. on a business day, the REP shall send a request to the TDU to remove the switch-hold by Noon (12:00 p.m.) of the next business day. If the TDU receives the request by 1:00 p.m. on a business day, the TDU shall remove the switch-hold by 8:00 p.m. of the same business day in which it receives the request to remove the switch-hold from the REP.

(3) The REP shall submit a request to remove a switch-hold pursuant to subsection (l)(6) of this section to the TDU, such that the TDU will remove the switch-hold on or before the customer's contract expiration date.

(4) If a REP erroneously places a switch-hold flag on an ESI ID, thus preventing a legitimate switch, or does not remove the switch-hold within the timeline described in paragraph (2) of this subsection, the REP shall be considered to have committed a Class B Violation (as defined in §25.8(b) of this title (relating to Classification System for Violations of Statutes, Rules, and Orders Applicable to Electric Service Providers)) for purposes of any administrative penalties imposed by the commission.

(n) **Annual reporting requirement.** In its annual report filed pursuant to §25.107 of this title (relating to Certification of Retail Electric Providers (REPs)) and §25.491 of this title (relating to Record Retention and Reporting Requirements), each REP shall include:

(1) A statement summarizing any low-income payment options and low-income payment assistance programs that are offered by or available from the REP;

(2) Information regarding a REP's bill payment assistance program created pursuant to subsection (g) of this section shall include:

(A) the total amount of customer donations;

(B) the amount of money set aside for bill payment assistance;

(C) the assistance agency or agencies selected to disburse funds to residential customers;

(D) the amount of money disbursed by the REP or provided to each assistance agency to disburse funds to residential customers; and

(E) the number of customers who had a switch-hold applied during the year.

(3) A statement confirming whether the REP, at the time of filing its annual report, has obtained the low-income customer identification service from the Low Income List Administrator (LILA) in accordance with §25.45 of this title, and whether the REP, at the time of filing its annual report, intends to obtain the low-income identification service from the LILA in the next fiscal year.

§25.481. Unauthorized Charges.

(a) **Authorization of charges.** Any services offered by the retail electric provider (REP) that will be billed on the customer's electric bill shall be authorized by the customer consistent with this section.

(b) **Requirements for billing charges.** A REP shall meet all of the following requirements before including any charges on the customer's electric bill:

(1) The REP shall inform the customer of the product or service being offered, including all associated charges, and explicitly inform the customer that the associated charges for the product or service will appear on the customer's electric bill.

(2) The customer must clearly and explicitly consent to obtaining the product or service offered and to having the associated charges appear on the customer's electric bill. The REP shall document the authorization in accordance with §25.474 of this title (relating to Selection of Retail Electric Provider). The documentation of the authorization shall be maintained by the REP for at least 24 months.

(3) The REP shall provide the customer with a toll-free telephone number the customer may call and an address to which the customer may write to resolve any billing dispute and to answer questions.

(c) **Responsibilities for unauthorized charges.**

(1) If a REP charges a customer's electric bill for any product or service without proper customer authorization, the REP shall promptly, but not later than 45 days thereafter:

(A) discontinue providing the product or service to the customer and cease charging the customer for the unauthorized product or service;

(B) remove the unauthorized charge from the customer's bill;

(C) refund or credit to the customer the money that has been paid by the customer for any unauthorized charge, and if any unauthorized charge that has been paid is not refunded or credited within three billing cycles, pay interest at an annual rate established by the commission pursuant to §25.478(f) of this title (relating to Credit Requirements and Deposits) on the amount of any unauthorized charge until it is refunded or credited; and

(D) upon the customer's request, provide the customer, free of charge, with all billing records under its control related to any unauthorized charge within 15 business days after the date of the removal of the charge from the customer's electric bill.

(2) A REP shall not:

(A) seek to disconnect electric service to any customer for nonpayment of an unauthorized charge;

(B) file an unfavorable credit report against a customer who has not paid charges that the customer has alleged were unauthorized unless the dispute regarding the unauthorized charges is ultimately resolved against the customer. The customer remains obligated to pay any charges that are not in dispute; or

(C) re-bill the customer for any unauthorized charge.

(3) In the event that a REP erroneously files an unfavorable credit report against a customer who has not paid charges that the customer has alleged were unauthorized, the REP must correct the credit report without delay.

(4) A REP shall maintain for at least 24 months a record of every customer who has experienced any unauthorized charge for a product or service on the customer's electric bill and has notified the REP of the unauthorized charge. The record shall contain for each unauthorized charge:

(A) the date the customer requested that the REP remove the unauthorized charge from the customer's electric bill;

(B) the date the unauthorized charge was removed from the customer's electric bill; and

(C) the date the customer was refunded or credited any money that the customer paid for the unauthorized charges.

(d) **Notice to customers.** Any bill sent to a residential and small commercial customer from a REP shall include a statement, prominently located on the bill, that if the customer believes the bill includes unauthorized charges, the customer should contact the REP to dispute such charges and, if not satisfied with the REP's review may file a complaint with the Public Utility Commission of Texas, P.O. Box 13326, Austin, Texas 78711-3326, (512) 936-7120 or toll-free in Texas at (888) 782-8477. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136.

(e) **Compliance and enforcement.**
(1) A REP shall provide proof of the customer's authorization and verification to the customer and/or the commission upon request.
(2) A REP shall provide a copy of records maintained under the requirements of subsection (c)(4) of this section to the commission or commission staff upon request.

§25.482. Prompt Payment Act.

(a) **Application**. This section applies to billing by an aggregator or a retail electric provider (REP) to a "governmental entity" as defined in Tex. Gov't Code, Chapter 2251, the Prompt Payment Act (PPA). This section controls over other sections of this chapter to the extent that they conflict.

(b) **Time for payment by a governmental entity**. A payment by a governmental entity subject to the PPA shall become overdue as provided in the PPA.

(c) **Disputed bills.** If there is a billing dispute between a governmental entity and an aggregator or a REP about any bill for aggregator or REP service, the dispute shall be resolved as provided in the PPA.

(d) **Interest on overdue payment**. Interest on an overdue governmental entity payment shall be calculated by the governmental entity pursuant to the terms of the PPA and remitted to the ESP with the overdue payment.

(e) **Notice**. An aggregator or REP shall provide written notice to all of its non-residential customers of the applicability of the PPA to the aggregator's or REP's service to governmental entities. This notice shall be completed within six months of the effective date of this section for existing non-residential customers and, within three months of the effective date of this section, shall be provided to a new customer at or before the time that the terms of service are provided to the customer. An aggregator's or REP's failure to provide this notice does not give rise to any independent claim under the PPA, nor does this notice initiate or terminate any party's rights or obligations under the PPA.

   (1) The failure of an aggregator or REP to provide written notice in accordance with this subsection may be considered in a PPA billing complaint.

   (2) The failure of a governmental entity to inform the aggregator or REP of its status as a governmental entity may be considered in a PPA billing complaint.

§25.483. Disconnection of Service.

(a) **Disconnection and reconnection policy**. Only a transmission and distribution utility (TDU), municipally owned utility, or electric cooperative shall perform physical disconnections and reconnections. Unless otherwise stated, it is the responsibility of a retail electric provider (REP) to request such action from the appropriate TDU, municipally owned utility, or electric cooperative in accordance with that entity's relevant tariffs, in accordance with the protocols established by the registration agent, and in compliance with the requirements of this section. If a REP chooses to have a customer's electric service disconnected, it shall comply with the requirements in this section. Nothing in this section requires a REP to request that a customer's service be disconnected.

(b) **Disconnection authority.**
   (1) Any REP may authorize the disconnection of a medium non-residential or large non-residential customer, as that term is defined in §25.43 of this title (relating to Provider of Last Resort (POLR)).
   (2) Except as provided in subsection (d) of this section, all REPs shall have the authority to authorize the disconnection of residential and small non-residential customers pursuant to commission rules. Prior to authorizing disconnections for non-payment in accordance with this paragraph, a REP shall:
      (A) test all necessary electronic transactions related to disconnections and reconnections of service; and
      (B) file an affidavit from an officer of the company, in a project established by the commission for this purpose, affirming that the REP understands and has trained its personnel on the commission's rule requirements related to disconnection and reconnection, and has adequately tested the transactions described in subparagraph (A) of this paragraph.

(c) **Disconnection with notice**. A REP having disconnection authority under the provisions of subsection (b) of this section, including the POLR, may authorize the disconnection of a customer's electric service after proper notice and not before the first day after the disconnection date in the notice for any of the following reasons:
   (1) failure to pay any outstanding bona fide debt for electric service owed to the REP or to make deferred payment arrangements by the date of disconnection stated on the disconnection notice. Payment of the delinquent bill at the REP's authorized payment agency is considered payment to the REP;
   (2) failure to comply with the terms of a deferred payment agreement made with the REP;
   (3) violation of the REP's terms and conditions on using service in a manner that interferes with the service of others or the operation of nonstandard equipment, if a reasonable attempt has been made to notify the customer and the customer is provided with a reasonable opportunity to remedy the situation;
   (4) failure to pay a deposit as required by §25.478 of this title (relating to Credit Requirements and Deposits); or
   (5) failure of the guarantor to pay the amount guaranteed, when the REP has a written agreement, signed by the guarantor, which allows for disconnection of the guarantor's service.

(d) **Disconnection without prior notice**. Any REP or TDU may, at any time, authorize disconnection of a customer's electric service without prior notice for any of the following reasons:
   (1) Where a known dangerous condition exists for as long as the condition exists. Where reasonable, given the nature of the hazardous condition, the REP, or its agent, shall post a notice of disconnection and the reason for the disconnection at the place of common entry or upon the front door of each affected residential unit as soon as possible after service has been disconnected;

(2) Where service is connected without authority by a person who has not made application for service;
(3) Where service is reconnected without authority after disconnection for nonpayment;
(4) Where there has been tampering with the equipment of the transmission and distribution utility, municipally owned utility, or electric cooperative; or
(5) Where there is evidence of theft of service.

(e) **Disconnection prohibited**. A REP having disconnection authority under the provisions of subsection (b) of this section shall not authorize a disconnection for nonpayment of a customer's electric service for any of the following reasons:
(1) Delinquency in payment for electric service by a previous occupant of the premises;
(2) Failure to pay for any charge that is not for electric service regulated by the commission, including competitive energy service, merchandise, or optional services;
(3) Failure to pay for a different type or class of electric service unless charges for such service were included on that account's bill at the time service was initiated;
(4) Failure to pay charges resulting from an underbilling, except theft of service, more than six months prior to the current billing;
(5) Failure to pay disputed charges, except for the amount not under dispute, until a determination as to the accuracy of the charges has been made by the REP or the commission, and the customer has been notified of this determination;
(6) Failure to pay charges arising from an underbilling due to any faulty metering, unless the meter has been tampered with or unless such underbilling charges are due under §25.126 of this title (relating to Adjustments Due to Non-Compliant Meters and Meter Tampering in Areas Where Customer Choice Has Been Introduced); or
(7) Failure to pay an estimated bill other than a bill rendered pursuant to an approved meter-reading plan, unless the bill is based on an estimated meter read by the TDU.

(f) **Disconnection on holidays or weekends.**
(1) A REP having disconnection authority under the provisions of subsection (b) of this section shall not request disconnection of a customer's electric service for nonpayment on a holiday or weekend, or the day immediately preceding a holiday or weekend, unless the REP's personnel are available on those days to take payments, make payment arrangements with the customer, and request reconnection of service.
(2) Unless a dangerous condition exists or the customer requests disconnection, a TDU shall not disconnect a customer's electric service on a holiday or weekend, or the day immediately preceding a holiday or weekend, unless the personnel of the TDU are available to reconnect service on all of those days.

(g) **Disconnection of Critical Care Residential Customers**. A REP having disconnection authority under the provisions of subsection (b) of this section shall not authorize a disconnection for nonpayment of electric service at a permanent, individually metered dwelling unit of a delinquent Critical Care Residential Customer when that customer establishes that disconnection of service will cause some person at that residence to become seriously ill or more seriously ill.
(1) Each time a Critical Care Residential Customer seeks to avoid disconnection of service under this subsection, the customer shall accomplish all of the following by the stated date of disconnection:
(A) Have the person's attending physician (for purposes of this subsection, the "physician" shall mean any public health official, including medical doctors, doctors of osteopathy, nurse practitioners, registered nurses, and any other similar medical professional) contact the REP to confirm that the customer is a Critical Care Residential Customer;
(B) Have the person's attending physician submit a written statement to the REP confirming that the customer is a Critical Care Residential Customer; and

(C) Enter into a deferred payment plan.

(2) The prohibition against service disconnection of a Critical Care Residential Customer provided by this subsection shall last 63 days from the issuance of the bill for electric service or a shorter period agreed upon by the REP and the customer, emergency (secondary) contact listed on the commission-approved application form, or attending physician. If the Critical Care Residential Customer does not accomplish the requirements of paragraph (1) of this subsection:

(A) The REP shall provide written notice to the Critical Care Residential Customer and the emergency contact listed on the commission-approved application form of its intention to disconnect service not later than 21 days prior to the date that service would be disconnected. Such notice shall be a separate mailing or hand delivered notice with a stated date of disconnection with the words “disconnection notice” or similar language prominently displayed. If the REP has offered and the customer has agreed for the customer and/or emergency contact to receive disconnection notices from the REP by email, a separate email with the words “disconnection notice” or similar language in the subject line shall be sent in addition to the separate mailing or hand delivered notice. Except as provided in this subsection, the notice shall comply with the requirements of subsections (l) and (m) of this section; and

(B) Prior to disconnecting a Critical Care Residential Customer, a TDU shall contact the customer and the emergency contact listed on the commission-approved application form. If the TDU does not reach the customer and emergency contact by phone, the TDU shall visit the premises, and, if there is no response, shall leave a door hanger containing the pending disconnection information and information on how to contact the REP and TDU.

(3) If, in the normal performance of its duties, a TDU obtains information that a customer scheduled for disconnection may qualify for delay of disconnection pursuant to this subsection, and the TDU reasonably believes that the information may be unknown to the REP, the TDU shall delay the disconnection and promptly communicate the information to the REP. The TDU shall disconnect such customer if it subsequently receives a confirmation of the disconnect notice from the REP. Nothing herein should be interpreted as requiring a TDU to assess or to inquire as to the customer’s status before performing a disconnection when not otherwise required.

(4) If a TDU refuses to disconnect a Critical Care Residential Customer pursuant to this subsection, it shall cease charging all transmission and distribution charges and surcharges, except securitization-related charges, for that premises to the REP.

(h) **Disconnection of Chronic Condition Residential Customers.** A REP having disconnection authority under the provisions of subsection (b) of this section shall not authorize a disconnection for nonpayment of electric service at a permanent, individually metered dwelling unit of a delinquent customer when that customer has been designated as a Chronic Condition Residential Customer pursuant to §25.497 of this title (relating to Critical Load Industrial Customers, Critical Load Public Safety Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers), except as provided in this subsection. The REP shall notify the Chronic Condition Residential Customer and the emergency contact listed on the commission-approved application form with a written notice of its intention to disconnect service not later than 21 days prior to the date that service would be disconnected. Such notice shall be a separate mailing or hand delivered notice with a stated date of disconnection with the words “disconnection notice” or similar language prominently displayed. If the REP has offered and the customer has agreed for the customer and/or emergency contact to receive disconnection notices from the REP by email, a separate email with the words “disconnection notice” or similar language in the subject line shall be also be sent in addition to the separate mailing or hand delivered notice. Except as provided in this subsection, the notice shall comply with the requirements of subsections (l) and (m) of this section.

(i) **Disconnection of energy assistance clients**.

(1) A REP having disconnection authority under the provisions of subsection (b) of this section shall not authorize a disconnection for nonpayment of electric service to a delinquent residential customer for a billing period in which the REP receives a pledge, letter of intent, purchase order, or other notification that the energy assistance provider is forwarding sufficient payment to continue service provided that such pledge, letter of intent, purchase order, or other notification is received by the due date stated on the disconnection notice, and the customer, by the due date on the disconnection notice, either pays or makes payment arrangements to pay any outstanding debt not covered by the energy assistance provider.

(2) If an energy assistance provider has requested monthly usage data pursuant to §25.472(b)(4) of this title (relating to Privacy of Customer Information), the REP shall extend the final due date on the disconnection notice, day for day, from the date the usage data was requested until it is provided.

(3) A REP shall allow at least 45 days for an energy assistance provider to honor a pledge, letter of intent, purchase order, or other notification before submitting the disconnection request to the TDU.

(4) A REP may request disconnection of service to a customer if payment from the energy assistance provider's pledge is not received within the time frame agreed to by the REP and the energy assistance provider, or if the customer fails to pay any portion of the outstanding balance not covered by the pledge.

(j) **Disconnection during extreme weather**. A REP having disconnection authority under the provisions of subsection (b) of this section shall not authorize a disconnection for nonpayment of electric service for any customer in a county in which an extreme weather emergency occurs. A REP shall offer residential customers a deferred payment plan upon request by the customer that complies with the requirements of §25.480 of this title (relating to Bill Payment and Adjustments) for bills that become due during the weather emergency.

(1) The term "extreme weather emergency" shall mean a day when:

(A) the previous day's highest temperature did not exceed 32 degrees Fahrenheit, and the temperature is predicted to remain at or below that level for the next 24 hours anywhere in the county, according to the nearest National Weather Service (NWS) reports; or

(B) the NWS issues a heat advisory for a county, or when such advisory has been issued on any one of the preceding two calendar days in a county.

(2) A TDU shall notify the commission of an extreme weather emergency in a method prescribed by the commission, on each day that the TDU has determined that an extreme weather emergency has been issued for a county in its service area. The initial notice shall include the county in which the extreme weather emergency occurred and the name and telephone number of the utility contact person.

(k) **Disconnection of master-metered apartments**. When a bill for electric service is delinquent for a master-metered apartment complex:

(1) The REP having disconnection authority under the provisions of subsection (b) of this section shall send a notice to the customer as required by this subsection. At the time such notice is issued, the REP, or its agents, shall also inform the customer that notice of possible disconnection will be provided to the tenants of the apartment complex in six days if payment is not made before that time.

(2) At least six days after providing notice to the customer and at least four days before disconnecting, the REP shall post a minimum of five notices in English and Spanish in conspicuous areas in the corridors or other public places of the apartment complex. Language in the notice shall be in large type and shall read: "Notice to residents of (name and address of apartment complex): Electric

service to this apartment complex is scheduled for disconnection on (date), because (reason for disconnection)."

(l) **Disconnection notices**. A disconnection notice for nonpayment shall:
(1) not be issued before the first day after the bill is due;
(2) be a separate mailing or hand delivered notice with a stated date of disconnection with the words "disconnection notice" or similar language prominently displayed or, if the REP has offered and the customer has agreed to receive disconnection notices from the REP by email, be a separate email with the words "disconnection notice" or similar language in the subject line. The REP may send the disconnection notice concurrently with the request for a deposit;
(3) have a disconnection date that is not a holiday, weekend day, or day that the REP's personnel are not available to take payments, and is not less than ten days after the notice is issued; and
(4) include a statement notifying the customer that if the customer needs assistance paying the bill by the due date, or is ill and unable to pay the bill, the customer may be able to make some alternate payment arrangement, establish a deferred payment plan, or possibly secure payment assistance. The notice shall also advise the customer to contact the provider for more information.

(m) **Contents of disconnection notice**. Any disconnection notice shall include the following information:
(1) The reason for disconnection;
(2) The actions, if any, that the customer may take to avoid disconnection of service;
(3) The amount of all fees or charges which will be assessed against the customer as a result of the default;
(4) The amount overdue;
(5) A toll-free telephone number that the customer can use to contact the REP to discuss the notice of disconnection or to file a complaint with the REP, and the following statement: "If you are not satisfied with our response to your inquiry or complaint, you may file a complaint by calling or writing the Public Utility Commission of Texas, P.O. Box 13326, Austin, Texas, 78711-3326; Telephone: (512) 936-7120 or toll-free in Texas at (888) 782-8477. Hearing and speech impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. Complaints may also be filed electronically at www.puc.texas.gov/ocp/complaints/complain.cfm;"
(6) If a deposit is being held by the REP on behalf of the customer, a statement that the deposit will be applied against the final bill (if applicable) and the remaining deposit will be either returned to the customer or transferred to the new REP, at the customer's designation and with the consent of both REPs;
(7) The availability of deferred payment or other billing arrangements, from the REP, and the availability of any state or federal energy assistance programs and information on how to get further information about those programs; and
(8) A description of the activities that the REP will use to collect payment, including the use of consumer reporting agencies, debt collection agencies, small claims court, and other remedies allowed by law, if the customer does not pay or make acceptable payment arrangements with the REP.

(n) **Reconnection of service.** Upon a customer's satisfactory correction of the reasons for disconnection, the REP shall request the TDU, municipally owned utility, or electric cooperative to reconnect the customer's electric service as quickly as possible. The REP shall inform the customer when reconnection is expected to occur in accordance with the timelines set forth in this subsection and in §25.214 of this title (relating to Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities). For premises without a provisioned advanced meter with remote disconnect/reconnect capabilities, if a REP submits a standard reconnect request and the TDU completes the reconnect the same day, the TDU shall assess a standard reconnect fee. A TDU may assess a same-day reconnect fee only when the REP expressly requests a same-day reconnect and a REP may pass through a same-day reconnect fee to the customer only when the customer expressly requests a same-day reconnect. A REP shall send a reconnection request no later than the timelines in this subsection. The TDU shall complete the reconnection in accordance with the timelines in §25.214 of this title.

(1) For payments made before 12:00 p.m. on a business day, a REP shall send a reconnection request to the TDU no later than 2:00 p.m. on the same day.

(2) For payments made after 12:00 p.m. but before 5:00 p.m. on a business day, a REP shall send a reconnection request to the TDU by 7:00 p.m. on the same day.

(3) For payments made after 5:00 p.m. but before 7:00 p.m. on a business day, a REP shall send a reconnection request to the TDU by 9:00 p.m. on the same day.

(4) For payments made after 7:00 p.m. on a business day, a REP shall send a reconnection request to the TDU by 2:00 p.m. on the next business day.

(5) For payments made on a weekend day or a holiday, a REP shall send a reconnection request to the TDU by 2:00 p.m. on the first business day after the payment was made.

(6) In no event shall a REP fail to send a reconnection notice within 48 hours after the customer's satisfactory correction of the reasons for disconnection as specified in the disconnection notice.

(o) **Electric service disconnection of a non-submetered master metered multifamily property**.

(1) In this subsection, "non-submetered master metered multifamily property" means an apartment, a leased or owner-occupied condominium, or one or more buildings containing at least 10 dwellings that receive electric utility service that is master metered but not submetered.

(2) A REP shall send a written notice of service disconnection to a municipality before authorizing disconnection of service to a non-submetered master metered multifamily property for nonpayment if:

(A) the property is located in the municipality; and

(B) the municipality establishes an authorized representative to receive the notice as described by paragraph (3) of this subsection.

(3) No later than January 1st of every year, a municipality wishing to receive notice of disconnection of electric service to a non-submetered master metered multifamily property shall provide the commission with the contact information for the municipality's authorized representative referenced by paragraph (2) of this subsection by submitting that person's name, title, direct mailing address, telephone number, and email address in a P.U.C. Project Number to be established annually for that purpose. The email address provided by the municipality may be for a general mailbox accessible by the authorized representative established for the purpose of receiving such notices.

(4) After January 1st, but no later than January 15th of every year, the commission shall post on its public website the contact information received from every municipality pursuant to paragraph (3) of this subsection. The contact information posted by the commission shall remain in effect during the subsequent 12-month period of February 1 through January 31 for the purpose of the written notice of disconnection required by paragraph (2) of this subsection.

(5) The retail electric provider shall email the written notice required by this subsection to the municipality's authorized representative not later than the 10th day before the date electric service is scheduled for disconnection. Additional notice may be provided by third-party commercial carrier delivery or certified mail.

(6) The customer safeguards provided by this subchapter are in addition to safeguards provided by other law or agency rules.

(7) This subsection does not prohibit a municipality or the commission from adopting customer safeguards that exceed the safeguards provided by this chapter.

§25.484. Electric No-Call List.

(a) **Purpose.** This section implements the Public Utility Regulatory Act (PURA) §39.1025, relating to Limitations on Telephone Solicitation, and the Texas Business & Commerce Code Annotated (Bus. & Comm. Code) §44.103 relating to rules, customer information, and isolated violations of the Texas no-call list.

(b) **Application**. This section applies to retail electric providers (REPs) as defined in §25.5 of this title (relating to Definitions). A REP acting as a telemarketer, as defined by §26.37 of this title (relating to Texas No-Call List), is also subject to the provisions of §26.37 of this title.

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

(1) **Consumer good or service** — For purposes of this section, consumer good or service has the same meaning as Business & Commerce Code §44.002(3) relating to Definitions.

(2) **Electric no-call database —** Database administered by the commission or its designee that contains the names, addresses, telephone numbers and dates of registration for all electric no-call registrants. Lists or other information generated from the electric no-call database shall be deemed to be a part of the database for purposes of enforcing this section.

(3) **Electric no-call list** — List that is published and distributed as required by subsection (f)(2) of this section.

(4) **Electric no-call registrant** -- A person who is either:

(A) An electric customer who registered prior to May 27, 2005, by application and payment of accompanying fee, for the electric no-call list; or

(B) A nonresidential electric customer who registered on or after May 27, 2005, by application and payment of accompanying fee, for the electric no-call list.

(5) **Established business relationship** — A prior or existing relationship that has not been terminated by either party, and that was formed by voluntary two-way communication between a person and a consumer regardless of whether consideration was exchanged, regarding consumer goods or services offered by the person.

(6) **Telemarketing call** — An unsolicited telephone call made to:

(A) solicit a sale of a consumer good or service;

(B) solicit an extension of credit for a consumer good or service; or

(C) obtain information that may be used to solicit a sale of a consumer good or service or to extend credit for sale.

(7) **Telephone call** — A call or other transmission that is made to or received at a telephone number within an exchange in the state of Texas, including but not limited to:

(A) a call made by an automatic dial announcing device (ADAD); or

(B) a transmission to a facsimile recording device.

(8) **Telemarketer** – A person who makes or causes to be made a telemarketing call that is made to a telephone number in an exchange in the state of Texas.

(d) **Requirement of REPs.**

(1) A REP shall not make or cause to be made a telemarketing call to a telephone number that has been published for more than 60 calendar days on the electric no-call list.

(2) A REP shall purchase each published version of the electric no-call list unless:

(A) the entirety of the REP's business is comprised of telemarketing calls that are exempt pursuant to subsection (e) of this section;

(B) a REP has a written contractual agreement with another telemarketer to make telemarketing calls on behalf of the REP and that telemarketer is contractually obligated to comply with all requirements of this section. In the absence of a written contract that requires the telemarketer to comply with all requirements of this section, the REP and the telemarketer making telemarketing calls on behalf of the REP are both liable for violations of this section.

(e) **Exemptions.** This section shall not apply to a telemarketing call made:

(1) By an electric no-call registrant that is the result of a solicitation by a REP or in response to general media advertising by direct mail solicitations that clearly, conspicuously, and truthfully make all disclosures required by federal or state law;

(2) In connection with:

(A) An established business relationship; or

(B) A business relationship that has been terminated, if the call is made before the later of:

(i) the date of publication of the first electric no-call list on which the electric no-call registrant's telephone number appears; or

(ii) one year after the date of termination; or

(3) To collect a debt.

(f) **Electric no-call database.**

(1) **Administrator.** The commission or its designee shall establish and provide for the operation of the electric no-call database.

(2) **Distribution of database.**

(A) Timing. Beginning on April 1, 2002, the administrator of the electric no-call database will update and publish the entire electric no-call list on January 1, April 1, July 1, and October 1 of each year;

(B) Fees. The electric no-call list shall be made available to subscribing REPs for a set fee not to exceed $75 per list per quarter;

(C) Format. The commission or its designee will make the electric no-call list available to subscribing REPs by:

(i) electronic internet access in a downloadable format;

(ii) Compact Disk Read Only Memory (CD-ROM) format;

(iii) paper copy, if requested by the REP; and

(iv) any other format agreed upon by the current administrator of the no-call database and the subscribing REP.

(3) **Intended use of the electric no-call database and electric no-call list.**

(A) The electric no-call database shall be used only for the intended purposes of creating an electric no-call list and promoting and furthering statutory mandates in accordance with PURA §39.1025 and the Business & Commerce Code, Chapter 44 relating to Telemarketing. Neither the electric no-call database nor a published electric no-call list shall be transferred, exchanged or resold to a non-subscribing entity, group, or individual, regardless of whether compensation is exchanged.

(B) The no-call database is not open to public inspection or disclosure.

(C) The administrator shall take all necessary steps to protect the confidentiality of the no-call database and prevent access to the no-call database by unauthorized parties.

(4) **Penalties for misuse of information.** Improper use of the electric no-call database or a published electric no-call list by the administrator, REPs, or any other person, regardless of the method of attainment, shall be subject to administrative penalties and enforcement provisions contained in §22.246 of this title (relating to Administrative Penalties).

(g) **Notice.** A REP shall provide notice of the electric no-call list to its customers as specified by this subsection. In addition to the required notice, the REP may engage in other forms of customer notification.

(1) **Content of notice.** A REP shall provide notice in compliance with §25.473 of this title (relating to Non-English Language Requirements) that, at a minimum, clearly explains the following:
(A) Beginning January 1, 2002, customers may add their name, address and telephone number to a state-sponsored electric no-call list that is intended to limit the number of telemarketing calls received relating to the customer's choice of REPs;
(B) When a customer who registers for inclusion on the electric no-call list can expect to stop receiving telemarketing calls on behalf of a REP;
(C) A customer must pay a fee to register for the electric no-call list;
(D) Registration of a telephone number on the electric no-call list expires on the fifth anniversary of the date the number is first published on the list;
(E) Registration of a telephone number on the electric no-call list can be accomplished via the United States Postal Service, Internet, or telephonically;
(F) The customer registration fee, which cannot exceed five dollars per term, must be paid by credit card when registering online or by telephone. When registering by mail, the fee must be paid by credit card, check or money order;
(G) The toll-free telephone number, website address, and mailing address for registration; and
(H) A customer that registers for inclusion on the electric no-call list may continue to receive calls from telemarketers other than REPs, and a statement that the customer may instead or may also register for the Texas no-call list that is intended to limit telemarketing calls regarding consumer goods and services in general, including electric service.

(2) **Publication of notice.** A REP shall include notice in its Terms of Service document or Your Rights as a Customer disclosure. The notice shall be easily legible, prominently displayed and comply with the requirements listed in paragraph (1) of this subsection.

(3) **Records of customer notification.** A REP shall provide a copy of records maintained under the requirements of this subsection as specified by §25.491 of this title (relating to Record Retention and Reporting Requirements).

(h) **Violations.**

(1) **Separate occurrence**. Each telemarketing call to a telephone number on the electric no-call list shall be deemed a separate occurrence.

(2) **Isolated occurrence**. A telemarketing call made to a number on the electric no-call list is not a violation of this section if the telemarketer complies with section (d)(2) and the telemarketing call is determined by the commission to be an isolated occurrence.
(A) An isolated occurrence is an event, action, or occurrence that arises unexpectedly and unintentionally, and is caused by something other than a failure to implement or follow reasonable procedures. An isolated occurrence may involve more than one separate occurrence, but it does not involve a pattern or practice.
(B) The burden to prove that the telemarketing call was made in error and was an isolated occurrence rests upon the REP who made (or caused to be made) the call. In order for a REP to assert as an affirmative defense that a potential violation of this section was an isolated occurrence, the REP must provide evidence of the following:
(i) The REP has purchased the most recently published update to the electric no-call list, unless the entirety of the REP's business is comprised of making or causing to be made telemarketing calls that are exempt pursuant to subsection (e) of this section and the REP can provide sufficient proof of such;
(ii) The REP has adopted and implemented written procedures to ensure compliance with this section and effectively prevent telemarketing calls that are in violation of this section, including taking corrective actions when appropriate;
(iii) The REP has trained its personnel in the established procedures; and
(iv) The telemarketing call that violated this section was made contrary to the policies and procedures established by the REP.

(i) **Record retention; Provision of records; Presumptions.**

(1) A REP shall maintain a record of all telephone numbers it has attempted to contact for telemarketing purposes, a record of all telephone numbers it has contacted for telemarketing purposes, and the date of each, for a period of not less than 24 months from the date the telemarketing call was attempted or completed.

(2) Upon request from the commission or commission staff, a REP shall provide, within 21 calendar days, all information in its possession and upon which it relies to demonstrate compliance with this section, relating to the commission's investigation of potential violations of the no-call list including, but not limited to, the call logs or phone records described in subsection (i)(1).

(3) Failure by a REP to respond, or to produce all information in its possession and upon which it relies to demonstrate compliance with this section, within the time specified in paragraph (2) of this subsection establishes a violation of this section.

(4) In response to a request from the commission pursuant to paragraph (2) of this subsection, a REP's failure to produce all telemarketing information in its possession and upon which it relies to demonstrate compliance with this section and, if applicable, to establish an affirmative defense pursuant to subsection (h)(2)(B) of this section, within the time specified in paragraph (2) of this subsection establishes a violation of this section.

(j) **Evidence.** Evidence provided by the customer that meets the standards set out in Texas Government Code §2001.081, including, but not limited to, one or more affidavits from the recipient of a telemarketing call is admissible to enforce the provisions of this section.

(k) **Enforcement and penalties.** The commission has jurisdiction to investigate REP violations of this section, as specified in §25.492 of this title (relating to Non-Compliance with Rules or Orders; Enforcement by the Commission).

§25.485. Customer Access and Complaint Handling.

(a) The purpose of this section is to ensure that retail electric customers have the opportunity for impartial and prompt resolution of disputes with REPs or aggregators.

(b) **Customer access.**

(1) Each retail electric provider (REP) or aggregator shall ensure that customers have reasonable access to its service representatives to make inquiries and complaints, discuss charges on customer's bills, terminate competitive service, and transact any other pertinent business.

(2) Telephone access shall be toll-free and shall afford customers a prompt answer during normal business hours.

(3) Each REP shall provide a 24-hour automated telephone message instructing the caller how to report any service interruptions or electrical emergencies.

(4) Each REP and aggregator shall employ 24-hour capability for accepting a customer's rescission of the terms of service by telephone, pursuant to rights of cancellation in §25.474(j) of this title (relating to Selection of Retail Electric Provider).

(c) **Complaint handling.** A residential or small commercial customer has the right to make a formal or informal complaint to the commission, and a terms of service agreement cannot impair this right. A REP or aggregator shall not require a residential or small commercial customer as part of the terms of service to engage in alternative dispute resolution, including requiring complaints to be submitted to arbitration or mediation by third parties. A customer other than a residential or small commercial customer may agree as part of the terms of service to engage in alternative dispute resolution, including requiring complaints to be submitted to arbitration or mediation by third parties. However, nothing in this subsection is intended to prevent a customer other than a residential or small commercial customer to file an informal or formal complaint with the commission if dissatisfied with the results of the alternative dispute resolution.

(d) **Complaints to REPs or aggregators.** A customer or applicant for service may submit a complaint in person, or by letter, facsimile transmission, e-mail, or by telephone to a REP or aggregator. The REP or aggregator shall promptly investigate and advise the complainant of the results within 21 days. A customer who is dissatisfied with the REP's or aggregator's review shall be informed of the right to file a complaint with the REP's or aggregator's supervisory review process, if available, and, if not available, with the commission and the Office of Attorney General, Consumer Protection Division. Any supervisory review conducted by the REP or aggregator shall result in a decision communicated to the complainant within ten business days of the request. If the REP or aggregator does not respond to the customer's complaint in writing, the REP or aggregator shall orally inform the customer of the ability to obtain the REP's or aggregator's response in writing upon request.

(e) **Complaints to the commission.**

(1) **Informal complaints.**

(A) If a complainant is dissatisfied with the results of a REP's or aggregator's complaint investigation or supervisory review, the REP or aggregator shall advise the complainant of the commission's informal complaint resolution process and the following contact information for the commission: Public Utility Commission of Texas, Customer Protection Division, P.O. Box 13326, Austin, Texas 78711-3326; (512) 936-7120 or in Texas (toll-free) 1-888-782-8477, fax (512) 936-7003, e-mail address: customer@puc.state.tx.us, Internet website address: www.puc.state.tx.us, TTY (512)936-7136, and Relay Texas (toll-free) 1-800-735-2989.

(B) Complainants should include sufficient information in a complaint to identify the complainant and the company for which the complaint is made and describe the issue specifically. The following information should be included in the complaint:

(i) The account holder's name, billing and service addresses, and telephone number;
(ii) The name of the REP or aggregator;
(iii) The customer account number or electric service identifier (ESI-ID);
(iv) An explanation of the facts relevant to the complaint;
(v) The complainant's requested resolution; and
(vi) Any documentation that supports the complaint, including copies of bills or terms of service documents.

(C) All REPs and aggregators shall provide the commission an email address to receive notification of customer complaints from the commission.

(D) The REP or aggregator shall investigate all informal complaints and advise the commission in writing of the results of the investigation within 21 days after the complaint is forwarded to the REP or aggregator.

(E) The commission shall review the complaint information and the REP or aggregator's response and notify the complainant of the results of the commission's investigation.

(2) While an informal complaint process is pending:

(A) The REP or aggregator shall not initiate collection activities, including disconnection of service or report the customer's delinquency to a credit reporting agency with respect to the disputed portion of the bill.

(B) A customer shall be obligated to pay any undisputed portion of the bill and the REP may pursue disconnection of service for nonpayment of the undisputed portion after appropriate notice.

(3) The REP or aggregator shall keep a record for two years after closure by the commission of all informal complaints forwarded to it by the commission. This record shall show the name and address of the complainant, the date, nature and adjustment or disposition of the complaint. Protests regarding commission-approved rates or rates and charges that are not regulated by the commission, but which are disclosed to the customer in the terms of service disclosures, need not be recorded.

(4) **Formal complaints.** If the complainant is not satisfied with the results of the informal complaint process, the complainant may file a formal complaint with the commission within two years of the date on which the commission closes the informal complaint. This process may include the formal docketing of the complaint as provided in §22.242 of this title (related to Complaints).

§25.487. Obligations Related to Move-In Transactions.

(a) **Applicability.** This section applies to all retail electric providers (REPs).

(b) **Definition.** For this section, the term "safety-net process" means a process developed and implemented by the market participants in the Texas retail electric market in 2002 to ensure that a customer who moves into a premise receives electric service in a timely manner. The safety-net process should be used for legitimate purposes and not to bypass standard rules and processes.

(c) **Standard move-in request**. A REP shall submit a move-in transaction to the registration agent electronically, in accordance with applicable protocols and guidelines of the independent organization to establish service for a new customer.

(d) **Safety-net move-in request**. In the event a REP does not receive a confirmation that the transmission and distribution utility (TDU) has received the appropriate move-in request transaction from the Electric Reliability Council of Texas (ERCOT), and does not receive a valid move-in rejection, the REP shall submit the move-in request using the safety-net process by noon on the business day prior to the customer's move-in date.

(1) In submitting a move-in request using the safety-net process, the REP establishes its right to serve the customer at the premise identified by the electric service identifier (ESI ID) from the date the TDU executes the move-in by connecting service to the premise. The date the TDU executes the move-in by connecting service to the premise is the effective date for all wires charges and fees associated with that ESI ID. This date will also be the effective date for the move-in when the applicable move-in electronic transactions are processed. The TDU may bill monthly wires charges and fees to the REP commencing with the effective date, but may not issue wires charges and fees or consumption records until the REP submits the electronic transaction.

(2) The REP shall ensure that the standard electronic move-in transaction is submitted to ERCOT in accordance with applicable protocols on or before the fifth business day after submitting the move-in through the safety net process, even if the physical move-in has already taken place as a result of being submitted through the safety net process. The REP, ERCOT, and the TDU shall work to ensure that the appropriate premise information and enrollment response transaction is sent to and received by the new REP and that the appropriate drop (due to switch request) transaction is sent to the losing REP of record as shown in ERCOT's systems.

(e) **Sunset provision for review of safety-net process**. By March 1, 2004, the commission shall, after input provided by market participants, review the safety-net process and determine whether it should be continued.

§25.488. Procedures for a Premise with No Service Agreement.

(a) **Applicability.** This section applies to all retail electric providers (REPs).

(b) **Service to premise with no service agreement.** If a REP finds that a current occupant at a premise for which the provider is shown as the REP of record in the ERCOT or TDU system is not the customer with whom the REP currently has a service agreement for retail electric service or the occupant is a customer whose prior service agreement has expired or is no longer in effect:

(1) the REP may establish service with the occupant. The REP shall obtain verification of the occupant's authorization to establish service with the REP consistent with the requirements of §25.474 of this title (relating to Selection or Change of Retail Electric Provider); or

(2) the REP with disconnection authority may issue a disconnection notice to the current occupant. The notice shall contain the following:

(A) The date the disconnection will occur, provided that the date shall not be sooner than ten days from the date the notice is issued;

(B) What actions the occupant must take if that occupant believes the notice is in error or desires to establish service with the REP; and

(C) A statement that informs the occupant of the right to obtain service from another licensed REP and that information about other REPs can be obtained from the commission.

§25.489. Treatment of Premises with No Retail Electric Provider of Record.

(a) **Applicability**. This section applies to all transmission and distribution utilities (TDUs) and retail electric providers (REPs) in areas open to retail customer choice.

(b) **Definition.** For this section, the term "no REP of record" means a premise that is receiving electricity equal to or greater than 150 kilowatt-hours (kWh) in a single meter reading cycle, but for which no REP is designated as serving the premise in the TDU's system.

(c) **Obligation of TDUs to identify premises with no REP of record**. Each TDU shall implement the following procedures to identify those premises that have no REP of record:

- (1) Each TDU shall prepare a No REP of Record List on a monthly basis, identifying all premises with consumption equal to or greater than 150 kilowatt hours (kWh) in a single meter reading cycle, but no REP of record in the TDU's Customer Information System;
- (2) Each TDU shall delete a premise from the list if there is evidence of erroneous meter reads for the premise;
- (3) Each TDU shall cross reference the list with ERCOT's pending orders to identify any move-in transactions that indicate that a REP is initiating service at a premise on the list and remove such premises from the list;
- (4) Each TDU shall review safety-net move-in requests to initiate service and remove such premises from the list; and
- (5) Each TDU shall review its internal systems for pending transactions and any correspondence from REPs claiming that a premise should be assigned to the REP. Any corresponding matches of premises shall be removed from the list.

(d) **Submission of No REP of Record List to REPs**.

- (1) Each TDU shall send the No REP of Record List to all REPs offering service in its service area each month;
- (2) Within five business days after the TDU sends the list, a REP shall inform the TDU in writing if it has a contract with a customer for a location on the list. The TDU shall delete all claimed premises from the list.
- (3) Nothing in this section is meant to absolve a REP of its responsibilities under §25.474 of this title (relating to Selection or Change of Retail Electric Provider).

(e) **Customer notification.** TDUs shall provide notice to all remaining premises in a standardized bilingual (English and Spanish) format consistent with subsection (g) of this section. TDUs may either provide notice by placing door hangers at each premise or by mailing notice to each premise.

(f) **Wires charges billed to customer with no REP of record.** A premise with no REP of record shall not constitute unauthorized use of service under the TDU's tariff for retail delivery service approved pursuant to §25.214 of this title (relating to Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities).

(g) **Format of notice.** The notice provided by the TDU to a customer on the final list of accounts with no REP of record shall have the identifying code #999 printed in bold letters to enable the REPs to identify customers contacting them as premises on the No REP of Record List and shall comply with the content requirements of this subsection.

- (1) The notice shall include the following information and be formatted as follows:

Date: ________________

Address: ____________________________________
ESI-ID: _____________________________________
DISCONNECT NOTICE
Code #999
The State of Texas requires all customers to have a Retail Electric Provider (REP) before receiving electric service. Our records indicate that you do not have a REP and are not receiving bills for electric service. Thus, you have not been billed for the electricity used at these premises.

In order to avoid any disruption in your service, you must select and enroll with a REP no more than ten days from the date of this notice. **To ensure proper identification of your premise, please inform the REP you have a Code 999 order to process.** If you do not enroll with a REP within ten days, electricity to this address will be disconnected.

If you have already contacted a REP to set up an electric service account, we urge you to contact your REP to check the status of your request to avoid disconnection of service.

A list of REPs is listed on this notice. If you have selected a REP and believe this notice is in error, please contact your REP immediately. You may call the Public Utility Commission of Texas (PUC) toll-free at 1-888-782-8477 to address any questions that your REP cannot answer.

(2) A comprehensive list of REPs serving residential customers in the TDU's territory, including each REP's toll-free number and website address (if available), shall be listed on the notice provided to residential premises. A comprehensive list of REPs serving commercial customers in the TDU's territory, including each company's toll-free number and website address (if available), shall be listed on the notice provided to commercial premises.

(h) **REP obligation to submit move-in transaction.** A REP that enrolls a premise in response to the TDU notice shall submit a move-in transaction, not a switch transaction, to the registration agent in accordance with the requirements of §25.487 of this title (relating to Obligations Related to Move-In Transactions).

(i) **Disconnection of premise with no REP of record.** Each TDU may disconnect a premise with no REP of record no earlier than ten days after the customer receives the TDU's notification required by this section. Prior to disconnecting the service for a premise with no REP of record, each TDU shall repeat the procedures listed in subsection (c) of this section (other than issuing notice) to prevent the disconnection of a customer who has initiated service with a REP. A TDU shall not disconnect any premise that has been claimed by a REP in accordance with this section.

(j) **Expedited reconnection of premise**. If a TDU disconnects a premise in error, the TDU shall reconnect a premise on an expedited basis in accordance with its tariff and commission rules, whichever process is shorter.

§25.490. Moratorium on Disconnection on Move-Out.

(a) **Applicability.** This section applies to all transmission and distribution utilities (TDUs) with respect to residential customers.

(b) **Moratorium on disconnection on move-out**. A TDU shall not disconnect a residential premise after receiving a move-out transaction unless the requirements of subsection (d) of this section have been met.

(c) **Reporting requirement.**

(1) A TDU shall report monthly to the commission its success rate in processing standard electronic move-in requests for residential customers. The success rate shall be measured based on whether the meter read and energizing of the premise is accomplished on the scheduled date. The report shall omit backdated move-in requests.

(2) A TDU shall also report to the commission its success rate in processing requests for reconnection of electric service. The success rate shall be measured based on whether the re-energizing of the premise is accomplished on the scheduled date.

(3) The reports shall be filed with the commission on or before the 15th day of the month following the last day of the reporting month.

(d) **Relaxation of moratorium on disconnection.** Upon approval from commission staff, a TDU may disconnect residential premises after receiving a move-out transaction, as defined in the ERCOT protocols. To achieve approval, the TDU must demonstrate through reports filed in accordance with subsection (c) of this section that it has for three consecutive months or more processed 95% or greater of all move-ins and requests for reconnection of electric service no later than the scheduled date. If a TDU's success rate falls below 95% for two consecutive months or below 90% in any one month, the TDU shall immediately notify commission staff in writing, and commission approval shall be automatically revoked.

(e) **Elimination of reporting requirement**. Once a TDU demonstrates a 95% success rate in completing reconnections and move-ins on the scheduled date for 12 consecutive months, it shall no longer be required to submit monthly reports, as required by subsection (c) of this section. However, upon request by the commission, a TDU shall file a report on its current success rate.

(f) **Notice of moratorium status.** The TDU shall notify each REP in its service territory each time it changes its status, pursuant to subsection (d) of this section, concerning the moratorium on move-out disconnections. The TDU shall not disconnect any residential premise prior to completion of this notice.

§25.491. Record Retention and Reporting Requirements.

(a) **Application**. This section does not apply to a municipally owned utility where it offers retail electric power or energy outside its certificated service territory or to a retail electric provider (REP) that is an electric cooperative.

(b) **Record retention.**

(1) Each REP and aggregator shall establish and maintain records and data that are sufficient to:

(A) Verify its compliance with the requirements of any applicable commission rules; and

(B) Support any investigation of customer complaints.

(2) All records required by this subchapter shall be retained for no less than two years, unless otherwise specified.

(3) Unless otherwise prescribed by the commission or its authorized representative, all records required by this subchapter shall be provided to the commission within 15 calendar days of its request.

(c) **Annual reports.** In its annual report, a REP shall report the information required by §25.107 of this title (relating to Certification of Retail Electric Providers (REPs)) to the commission and the Office of Public Utility Counsel (OPUC) and the following additional information on a form approved by the commission for the 12-month period ending December 31 of the prior year:

(1) The number of residential customers served, by nine-digit zip code and census tract, by month;

(2) The number of written denial of service notices issued by the REP, by month, by customer class, by nine-digit zip code and census tract;

(3) The number and total aggregated dollar amount of deposits held by the REP, by month, by customer class, by nine-digit zip code and census tract;

(4) Information relating to the REP's bill payment assistance program for residential electric customers required by §25.480(n)(1) of this title (relating to Bill Payment and Adjustments);

(5) The number of complaints received by the REP from residential customers for the following categories by month, by nine-digit zip code and census tract:

(A) Refusal of electric service, which shall include all complaints pertaining to the implementation of §25.477 of this title (relating to Refusal of Electric Service);

(B) Marketing and quality of customer service, which shall include complaints relating to the interfaces between the customer and the REP, such as, but not limited to, call center hold time, responsiveness of customer service representatives, and implementation of §25.472 of this title (relating to Privacy of Customer Information), §25.475 of this title (relating to General REP Requirements and Information Disclosures to Residential and Small Commercial Customers), §25.473 of this title (relating to Non-English Language Requirements), §25.476 of this title (relating to Renewable and Green Energy Verification), and §25.484 of this title (relating to Texas Electric No-Call List), and which shall not include issues for which the REP is not responsible, such as, but not limited to, power quality, outages, or technical failures of the registration agent;

(C) Unauthorized charges, which shall encompass all complaints pertaining to §25.481 of this title (relating to Unauthorized Charges);

(D) Enrollment, which shall encompass all complaints pertaining to the implementation of §25.474 of this title (relating to the Selection of Retail Electric Provider), §25.478 of this title (relating to Credit Requirements and Deposits), and §25.495 of this title (relating to Unauthorized Change of Retail Electric Provider);

(E) Accuracy of billing services, which shall encompass all complaints pertaining to the implementation of §25.479 of this title (relating to Issuance and Format of Bills); and

(F) Collection and service termination, and disconnection, which shall encompass all complaints pertaining to the implementation of §25.480 of this title, and §25.483 of this title (relating to Disconnection of Service).

(6) In reporting the number of informal complaints received pursuant to paragraph (4) of this subsection, a REP may identify the number of complaints in which it has disputed categorization or assignment pursuant to the provisions set forth in §25.485 of this title (relating to Customer Access and Complaint Handling).

(d) **Information regarding payment options and payment assistance programs.** With its annual report, a REP shall include a statement containing the information described in §25.480(n) of this title to the extent such information is not included in the form approved by the commission pursuant to subsection (c) of this section.

(e) **Additional information.** Upon written request by the commission, a REP or aggregator shall provide within 15 days any information, including but not limited to marketing information, necessary for the commission to investigate an alleged discriminatory practice prohibited by §25.471(c) of this title (relating to General Provisions of the Customer Protection Rules).

§25.492. Non-Compliance with Rules or Orders; Enforcement by the Commission.

(a) **Noncompliance.** An aggregator or retail electric provider (REP) that fails to comply with the Public Utility Regulatory Act (PURA) or commission order may, after notice and opportunity for hearing, be subject to any and all of the following available under the law, including, but not limited to:

(1) assessment of civil and administrative penalties under PURA §15.023;

(2) civil penalties under PURA §15.028;

(3) suspension or revocation of the applicable certification or registration or denial of a request for renewal or change in the terms associated with a certification; and

(4) such other relief directed to affected customers as allowed by law.

(b) **Commission investigation.** The commission may initiate a compliance or other enforcement proceeding upon its own initiative, after an incident has occurred, or a complaint has been filed, or a staff notice of probable noncompliance has been served. The commission shall coordinate this investigation with any investigation that may be or has been undertaken by the Office of the Attorney General.

(c) **Suspension and revocation of certification.** The commission may initiate a proceeding to seek either suspension or revocation of a REP's certification consistent with §25.107(j) of this title (relating to Certification of Retail Electric Providers), or an aggregators registration consistent with §25.111(j) of this title (relating to the Registration of Aggregators).

§25.493. Acquisition and Transfer of Customers from one Retail Electric Provider to Another.

(a) **Application.** This section applies when a retail electric provider (REP) acquires customers from another REP due to acquisition, merger, bankruptcy, or other similar reason.

(b) **Notice requirement.** Any REP other than a provider of last resort (POLR) that will acquire customers from another REP due to acquisition, merger, bankruptcy, or any other similar reason, shall provide notice the notice required by subsection (c) or (d) of this section to every affected customer. The notice may be in a billing insert or separate mailing, at least 30 days prior to the transfer. If legal or regulatory constraints prevent the sending of advance notice, the notice shall be sent promptly after all legal and regulatory impediments have been removed. The POLR shall comply with the requirements of §25.43 of this title (relating to Provider of Last Resort (POLR)). Transferring customers from one REP to another does not require advance commission approval, unless the transfer is due to abandonment of a REP. The acquiring REP shall also inform the commission or commission staff of the acquisition of customers.

(c) **Contents of notice for adverse changes in terms of service.** If the transfer of a customer will materially change the terms of service for the affected customer in an adverse manner, the notice shall:
(1) identify the current and acquiring REP;
(2) explain the reasons for the transfer of the customer’s account to the new REP;
(3) explain that the customer may select another REP without penalty due to the adverse change in the terms of service, and if the customer desires to do so, that they should contact another REP;
(4) identify the date that customers will be or were transferred to the acquiring REP;
(5) provide the new terms of service, including the Electricity Facts Label of the acquiring REP; and
(6) provide a toll-free number for a customer to call for additional information and the identity of the party being called.

(d) **Contents of notice for transfers with no adverse change in terms of service.** If a transfer of a customer will not result in a material adverse change to the terms of service for the affected customer, the notice is not required to contain the information required by subsection (c)(3) of this section.

(e) **Process to transfer customers.** The registration agent shall develop procedures to facilitate the expeditious transfer of large numbers of customers from one REP to another.

§25.495. Unauthorized Change of Retail Electric Provider.

(a) Process for resolving unauthorized change of retail electric provider (REP). If a REP is serving a customer without proper authorization pursuant to §25.474 of this title (relating to Selection of Retail Electric Provider), the REP, registration agent, and transmission and distribution utility (TDU) shall follow the procedures set forth in this subsection.

(1) Either the original REP or switching REP shall notify the registration agent of the unauthorized change of REP as promptly as possible, using the process approved by the registration agent.

(2) As promptly as possible following receipt of notice by the REP, the registration agent shall facilitate the prompt return of the customer to the original REP, or REP of choice in the case of a move-in.

(3) The affected REPs, the registration agent, and the TDU shall take all actions necessary to return the customer to the customer's original REP, or REP of choice in the case of a move-in, as quickly as possible. The original REP does not need to obtain an additional authorization from the customer pursuant to §25.474 of this title in order to effectuate the provision of this section.

(4) The affected REPs, the registration agent, and the TDU shall take all actions necessary to bill correctly all charges, so that the end result is that:

(A) the REP that served the customer without proper authorization shall pay all transmission and distribution charges associated with returning the customer to its original REP, or REP of choice in the case of a move-in;

(B) the original REP has the right to bill the customer pursuant to §25.480 of this title (relating to Bill Payment and Adjustment) at the price disclosed in its terms of service from either:

(i) the date the customer is returned to the original REP; or

(ii) any prior date chosen by the original REP for which the original REP had the authorization to serve the customer.

(C) the REP that served the customer without proper authorization shall refund all charges paid by the customer for the time period for which the original REP ultimately bills the customer within five business days after the customer is returned to the original REP, or REP of choice in the case of a move-in;

(D) the customer shall pay no more than the price at which the customer would have been billed had the unauthorized switch or move-in not occurred;

(E) the TDU has the right to seek collection of non-bypassable charges from the REP that ultimately bills the customer under subparagraph (B) of this paragraph; and

(F) the REP that ultimately bills the customer under subparagraph (B) of this paragraph is responsible for non-bypassable charges and wholesale consumption for the customer.

(5) The original REP shall provide the customer all benefits or gifts associated with the service that would have been awarded had the unauthorized switch or move-in not occurred, upon receiving payment for service provided during the unauthorized change;

(6) The affected REPs shall communicate with the customer as appropriate throughout the process of returning the customer to the original REP or REP of choice and resolving any associated billing issues.

(7) In a circumstance where paragraph (4) of this subsection is not applicable or its requirements cannot be effectuated, the market participants involved shall work together in good faith to rectify the unauthorized switch or move-in in a manner that affords the customer and market participants involved a level of protection comparable to that required in this subsection.

(b) Customer complaints, record retention and enforcement.

(1) Customers may file a complaint with the commission, pursuant to §25.485 of this title (relating to Customer Access and Complaint Handling), against a REP for an alleged failure to comply with the provisions of this section.

(2) Upon receipt of a customer complaint, each REP shall:
(A) respond to the commission within 21 calendar days after receiving the complaint and in the response to the complaint provide to the commission all documentation relied upon by the REP and related to the:
(i) authorization and verification to switch the customer's service; and
(ii) corrective actions taken to date, if any.
(B) cease any collection activity related to the alleged unauthorized switch or move-in until the complaint has been resolved by the commission.

(c) This section is effective June 1, 2004.

§25.497. Critical Load Industrial Customers, Critical Load Public Safety Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers.

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

(1) **Critical Load Public Safety Customer** -- A customer for whom electric service is considered crucial for the protection or maintenance of public safety, including but not limited to hospitals, police stations, fire stations, and critical water and wastewater facilities.

(2) **Critical Load Industrial Customer** -- An industrial customer for whom an interruption or suspension of electric service will create a dangerous or life-threatening condition on the retail customer's premises, is a "critical load industrial customer."

(3) **Chronic Condition Residential Customer** -- A residential customer who has a person permanently residing in his or her home who has been diagnosed by a physician as having a serious medical condition that requires an electric-powered medical device or electric heating or cooling to prevent the impairment of a major life function through a significant deterioration or exacerbation of the person's medical condition. If that serious medical condition is diagnosed or re-diagnosed by a physician as a life-long condition, the designation is effective under this section for the shorter of one year or until such time as the person with the medical condition no longer resides in the home. Otherwise, the designation or re-designation is effective for 90 days.

(4) **Critical Care Residential Customer** -- A residential customer who has a person permanently residing in his or her home who has been diagnosed by a physician as being dependent upon an electric-powered medical device to sustain life. The designation or redesignation is effective for two years under this section.

(b) **Eligibility for protections**. In order to be considered for designation under this section, an application for designation must be submitted by or on behalf of the customer.

(1) To be designated as a Critical Care Residential Customer or Chronic Condition Residential Customer, the commission-approved application form must be submitted to the TDU by a physician, in accordance with provisions of this section.

(2) To be designated as a Critical Load Public Safety Customer or a Critical Load Industrial Customer, the customer must notify the TDU. To be eligible for the protections provided under this section, the customer must have a determination of eligibility pending with or approved by the TDU. Eligibility shall be determined through a collaborative process among the customer, REP, and TDU, but in the event that the customer, REP and TDU are unable to agree on the designation, the TDU has the authority to make or decline to make the designation.

(c) **Benefits for Critical Load Public Safety Customers, Critical Load Industrial Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers**.

(1) A Critical Load Public Safety Customer or a Critical Load Industrial Customer qualifies for notifications of interruptions or suspensions of service as provided in Sections 4.2.5, 5.2.5, and 5.3.7.1 of the TDU's tariff for retail delivery service.

(2) A Critical Care Residential Customer or Chronic Condition Residential Customer qualifies for notification of interruptions or suspensions of service, as provided in Sections 4.2.5, 5.2.5, and 5.3.7.1, and for Critical Care Residential Customers protections against suspension or disconnection, as provided in Section 5.3.7.4(1)(D) and (E), of the TDU's tariff for retail delivery service.

(3) A Critical Care Residential Customer or Chronic Condition Residential Customer is also eligible for certain protections as described in §25.483 (relating to Disconnection of Service).

(4) Designation as a Critical Load Customer, Critical Care Residential Customer, or Chronic Condition Residential Customer does not guarantee the uninterrupted supply of electricity.

(d) **Notice to customers concerning Critical Care Residential Customer and Chronic Condition Residential Customer status**.

(1) A REP shall notify each residential applicant for service of the right to apply for Critical Care Residential Customer or Chronic Condition Residential Customer designation. This notice to an applicant for residential service shall be included in the Your Rights as a Customer document.

(2) All REPs that serve residential customers shall provide information about Critical Care Residential Customer and Chronic Condition Residential Customer designations to each residential customer two times a year.

(3) Upon a customer's request, the REP shall provide to the customer the application form for Critical Care Residential Customer and Chronic Condition Residential Customer designation.

(e) **Procedure for obtaining Critical Care Residential Customer or Chronic Condition Residential Customer designation.**

(1) The commission-approved application form shall instruct the customer to have the physician submit the application form by facsimile or other electronic means to the TDU. If the physician submits the form to the REP, the REP shall forward it to the TDU electronically no later than two business days from receipt of the form. The application form shall include a telephone number for reaching a person at the TDU who is capable of responding to questions from a physician or customer about the form during regular business hours.

(2) After the TDU receives the form, it shall evaluate the form for completeness. If the form is incomplete, no later than two business days after receiving the form, the TDU shall mail the form to the customer and explain in writing what information is needed to complete the form.

(3) If the TDU has returned the form as incomplete or has not finished processing the form within two business days from receipt of the form, the customer shall be designated as a Critical Care Residential Customer or Chronic Condition Residential Customer on a temporary basis pending final designation by the TDU. The temporary designation shall be based on the designation selected by the physician on the form if such designation was included; otherwise, the temporary designation shall be as a Critical Care Residential Customer. The TDU shall notify the customer's REP of such temporary designation using a standard market transaction. If the form is returned to the customer as incomplete, the temporary designation shall remain in effect for 14 days, after which the temporary designation shall expire and the application process must start over.

(4) Reasons that a TDU shall consider a form incomplete for an application for Critical Care Residential Customer or Chronic Condition Residential Customer designation include the omission of the name of the person for whom the protection is sought, contact information, physician signature, the designation as a Critical Care Residential Customer or Chronic Condition Residential Customer, and medical board license number of the customer's physician. Any additional mandatory information required for completeness shall be clearly identified on the commission-approved application form. A customer may, but it is not required to, include an emergency (secondary) contact in the application.

(5) The TDU shall not challenge the physician's determination of the customer's status, but shall apply the physician's designation of the customer as a Critical Care Residential Customer or Chronic Condition Residential Customer consistent with the information provided on the form and the definitions in this section. The TDU may verify the physician's identity and signature and may deny an application for designation, if it determines that the identity or signature of the physician is not authentic.

(6) The TDU shall notify the customer's REP using a standard market transaction and the customer of the final status of the application process, including whether the customer has been designated for Critical Care Residential Customer or Chronic Condition Residential Customer status. The TDU shall also notify the customer of the date a designation, if any, will expire, and whether the customer will receive a renewal notice. The TDU shall provide the emergency contact information (if applicable) to the REP using a standard market transaction. If the customer switches to a

different REP, the TDU shall provide the new REP with information on the customer's status and the emergency contact information (if applicable) using a standard market transaction.

(7) At the same time the TDU notifies the customer the final status of the customer's application, the TDU shall inform the customer of the customer's right to file a complaint with the commission pursuant to §22.242 of this title (relating to Complaints).

(8) The TDU shall notify Critical Care Residential Customers and Chronic Condition Residential Customers of the expiration of their designation in accordance with this subsection. The TDU shall notify the customer's REP using a standard market transaction when a customer is no longer designated as a Critical Care Residential Customer or a Chronic Condition Residential Customer.

(9) The TDU shall mail a renewal notice to a Chronic Condition Residential Customer whose designation was for a period longer than 90 days or a Critical Care Residential Customer, at least 45 days prior to the expiration date of the customer's designation. The renewal notice shall also be mailed to the emergency contact included on the commission-approved application form (if applicable). The renewal notice shall include the application form and an explanation of how to reapply for Critical Care Residential Customer or Chronic Condition Residential Customer designation. The renewal notice shall inform the customer that the current designation will expire unless the application form is returned by the expiration date of the existing designation.

(f) **Effect of Critical Care Residential Customer or Chronic Condition Residential Customer status on payment obligations**. A Critical Care Residential Customer or Chronic Condition Residential Customer designation pursuant to this section does not relieve a customer of the obligation to pay the REP for services provided, and a customer's service may be disconnected pursuant to §25.483 of this title.

(g) **TX SET changes**. In the first TX SET release after the effective date of this section, market transactions shall be included to address the requirements of this section.

(h) **Effective date**. The effective date of this section is January 1, 2011.

(i) **TDU annual report**. A TDU shall report to the commission by March 1 of each year beginning in 2012, the number of customers for each type of customer defined in subsection (a) of this section as of December 31 of the previous calendar year. The TDU report shall also include for the previous calendar year, for each type of customer defined in subsection (a) of this section, the number of applications that were rejected as a result of incomplete forms, the number of requests from REPs for disconnection, and the number of disconnections and reconnections completed. An interim report shall be filed by the TDU on April 1, 2011 for the time period from January 1, 2011 through March 1, 2011.

§25.498. Prepaid Service.

§25.500. Privacy of Advanced Metering System Information.

A transmission and distribution utility shall not sell, share, or disclose information generated, provided, or otherwise collected from an advanced metering system or meter information network, including information used to calculate charges for service, historical load data, and any other customer information; except the transmission and distribution utility may share such information with an affiliated corporation as defined in §25.5 of this title (relating to Definitions), or other third-party entity, if the information is to be used only for the purpose of:

(1) Providing electric utility service to the customer; or
(2) Other customer-approved services.

§25.501. Wholesale Market Design for the Electric Reliability Council of Texas.

(a) **General**. The protocols and other rules and requirements of the Electric Reliability Council of Texas (ERCOT) that implement this section shall be developed with consideration of microeconomic principles and shall promote economic efficiency in the production and consumption of electricity; support wholesale and retail competition; support the reliability of electric service; and reflect the physical realities of the ERCOT electric system. Except as otherwise directed by the commission, ERCOT shall determine the market clearing prices of energy and other ancillary services that it procures through auctions and the congestion rents that it charges or credits, using economic concepts and principles such as: shadow price of a constraint, marginal cost pricing, and maximizing the sum of consumer and producer surplus.

(b) **Bilateral markets and default provision of energy and ancillary capacity services**. ERCOT shall permit market participants to self-arrange (self-schedule or bilaterally contract for) energy and ancillary capacity services, except to the extent that doing so would adversely impact ERCOT's ability to maintain reliability. To the extent that a market participant does not self-arrange the energy and ancillary capacity services necessary to meet its obligations or to the extent that ERCOT determines that the market participant's self-arranged ancillary services will not be delivered, ERCOT shall procure energy and ancillary capacity services on behalf of the market participant to cover the shortfall and charge the market participant for the services provided.

(c) **Day-ahead energy market**. ERCOT shall operate a voluntary day-ahead energy market, either directly or through contract.

(d) **Adequacy of operational information.** ERCOT shall require resource-specific bid curves for energy and ancillary capacity services that it competitively procures in the day-ahead or operating day, and ERCOT shall use these bid curves or ex-ante mitigated bid curves to address market failure, as appropriate, in its operational decisions and financial settlements.

(e) **Congestion pricing.**

(1) ERCOT shall directly assign all congestion rents to those resources that caused the congestion.

(2) ERCOT shall be considered to have complied with paragraph (1) of this subsection if it complies with this paragraph. ERCOT shall settle each resource imbalance at its nodal locational marginal price (LMP) calculated pursuant to subsection (f) of this section; each load imbalance at its zonal price calculated pursuant to subsection (h) of this section; and congestion rents on each scheduled transaction for a resource and load pair at the difference between the nodal LMP at the resource injection location calculated pursuant to subsection (f) of this section and the zonal price at the load withdrawal location calculated pursuant to subsection (h) of this section.

(f) **Nodal energy prices for resources.** ERCOT shall use nodal energy prices for resources. Nodal energy prices for resources shall be the locational marginal prices, consistent with subsection (e) of this section, resulting from security-constrained, economic dispatch.

(g) **Energy trading hubs.** ERCOT shall provide information for energy trading hubs by aggregating nodes and calculating an average price for each aggregation, for each financial settlement interval.

(h) **Zonal energy prices for loads**. ERCOT shall use zonal energy prices for loads that consist of an aggregation of either the individual load node energy prices within each zone or the individual resource node energy prices within each zone. Individual load node or resource node energy prices shall be the locational marginal prices, consistent with subsection (e) of this section, resulting from security-constrained, economic dispatch. ERCOT shall maintain stable zones and shall notify market participants in advance of zonal boundary changes in order that the market participants will have an appropriate amount of time to adjust to the changes.

(i) **Congestion rights.** ERCOT shall provide congestion revenue rights (CRRs), but shall not provide physical transmission rights. ERCOT shall auction all CRRs, using a simultaneous combinatorial auction, except as otherwise ordered by the commission for any preassigned CRRs approved by the commission. CRRs shall not be subject to "use-it-or-lose-it" or "schedule-it-or-lose-it" restrictions and shall be tradable.

(j) **Pricing safeguards.** ERCOT shall apply pricing safeguards to protect against market failure, including market power abuse, consistent with direction provided by the commission.

(k) **Simultaneous optimization of ancillary capacity services**. For ancillary capacity services that it competitively procures in the day-ahead or operating day, ERCOT shall use simultaneous optimization and shall set prices for each service to the corresponding shadow price.

(l) **Multi-settlement system for procuring energy and ancillary capacity services**. For any energy and ancillary capacity services that it competitively procures in the day-ahead or operating day, ERCOT shall set a separate market clearing price for each procurement of a particular service.

(m) **Energy Storage**.

(1) For a storage facility that has more than one delivery point, ERCOT shall net the impact of those delivery points on the ERCOT system for settlement purposes.

(2) Wholesale storage occurs when electricity is used to charge a storage facility; the storage facility is separately metered from all other facilities including auxiliary facilities; and energy from the electricity is stored in the storage facility and subsequently re-generated and sold at wholesale as energy or ancillary services. Wholesale storage is wholesale load and ERCOT shall settle it accordingly, except that ERCOT shall settle wholesale storage using the nodal energy price at the electrical bus that connects the storage facility to the transmission system, or if the storage facility is connected at distribution voltage, the nodal price of the nearest electrical bus that connects to the transmission system. Wholesale storage is not subject to retail tariffs, rates, and charges or fees assessed in conjunction with the retail purchase of electricity. Wholesale storage shall not be subject to ERCOT charges and credits associated with ancillary service obligations, or other load ratio share or per megawatt-hour based charges and allocations. The owner or operator of electric storage equipment or facilities shall not make purchases of electricity for storage during a system emergency declared by ERCOT unless ERCOT directs that such purchases occur.

§25.502. Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas.

(a) **Purpose**. The purpose of this section is to protect the public from harm when wholesale electricity prices in markets operated by the Electric Reliability Council of Texas (ERCOT) in the ERCOT power region are not determined by the normal forces of competition.

(b) **Applicability**. This section applies to any entity, either acting alone or in cooperation with others, that buys or sells at wholesale energy, capacity, or any other wholesale electric service in a market operated by ERCOT in the ERCOT power region; any agent that represents such an entity in such activities; and ERCOT. This section does not limit the commission's authority to ensure reasonable ancillary energy and capacity service prices and to address market power abuse.

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

(1) **Competitive constraint** – A transmission element on which prices to relieve congestion are moderated by the normal forces of competition between multiple, unaffiliated resources.

(2) **Generation entity** – an entity that owns or controls a generation resource.

(3) **Market location** – the location for purposes of financial settlement of a service (*e.g.*, congestion management zone in a zonal market design or a node in a nodal market design).

(4) **Noncompetitive constraint** – A transmission element on which prices to relieve congestion are not moderated by the normal forces of competition between multiple, unaffiliated resources.

(5) **Resource –** a generation resource, or a load capable of complying with ERCOT instructions to reduce or increase the need for electrical energy or to provide an ancillary service (*i.e.*, a "load acting as a resource").

(6) **Resource entity –** an entity that owns or controls a resource.

(d) **Control of resources**. Each resource entity shall inform ERCOT as to each resource that it controls, and provide proof that is sufficient for ERCOT to verify control. In addition, the resource entity shall notify ERCOT of any change in control of a resource that it controls no later than 14 calendar days prior to the date that the change in control takes effect, or as soon as possible in a situation where the resource entity cannot meet the 14 calendar day notice requirement. For purposes of this section, "control" means ultimate decision-making authority over how a resource is dispatched and priced, either by virtue of ownership or agreement, and a substantial financial stake in the resource's profitable operation. If a resource is jointly controlled, the resource entities shall inform ERCOT of any right to use an identified portion of the capacity of the resource. Resources under common control shall be considered affiliated.

(e) **Reliability-must-run resources**. Except for the occurrence of a forced outage, a generation entity shall notify ERCOT in writing no later than 90 calendar days prior to the date on which it intends to cease or suspend operation of a generation resource for a period of greater than 180 calendar days. Unless ERCOT has determined that a generation entity's generation resource is not required for ERCOT reliability, the generation entity shall not terminate its registration of the generation resource with ERCOT unless it has transferred the generation resource to a generation entity that has a current resource entity agreement with ERCOT and the transferee registers that generation resource with ERCOT at the time of the transfer.

(1) Complaint with the commission. If, after 90 calendar days following ERCOT's receipt of the generation entity's notice, either ERCOT has not informed the generation entity that the generation resource is not needed for ERCOT reliability or both parties have not signed a reliability-must-run (RMR) agreement for the generation resource, then the generation entity may file a complaint with the commission against ERCOT, pursuant to §22.251 of this title (relating to Review of Electric Reliability Council of Texas (ERCOT) conduct).

(A) The generation entity shall have the burden of proof.

(B) Pursuant to §22.251(d) of this title, absent a showing of good cause to the commission to justify a later deadline, the generation entity's deadline to file the complaint is 35 calendar days after the 90th calendar day following ERCOT's receipt of the notice.

(C) The dispute underlying the complaint is not subject to ERCOT's alternative dispute resolution procedures.

(D) In its complaint, the generation entity may request interim relief pursuant to §22.125 of this title (relating to Interim Relief), an expedited procedural schedule, and identify any special circumstances pertaining to the generation resource at issue.

(E) Pursuant to §22.251(f) of this title, ERCOT shall file a response to the generation entity's complaint and shall include as part of the response all existing, non-privileged documents that support ERCOT's position on the issues identified by the generation entity pursuant to §22.251(d)(1)(C) of this title.

(F) The scope of the complaint may include the need for the RMR service; the reasonable compensation and other terms for the RMR service; the length of the RMR service, including any appropriate RMR exit options; and any other issue pertaining to the RMR service.

(G) Any compensation ordered by the commission shall be effective the 91st calendar day after ERCOT's receipt of the notice. If there is a pre-existing RMR agreement concerning the generation resource, the compensation ordered by the commission shall not become effective until the termination of the pre-existing agreement, unless the commission finds that the pre-existing RMR agreement is not in the public interest.

(H) If the generation entity does not file a complaint with the commission, the generation entity shall be deemed to have accepted ERCOT's most recent offer as of the 115th calendar day after ERCOT's receipt of the notice.

(2) Out-of-merit-order dispatch. The generation entity shall maintain the generation resource so that it is available for out-of-merit-order dispatch instruction by ERCOT until:

(A) ERCOT determines that the generation resource is not required for ERCOT reliability;

(B) any RMR agreement takes effect;

(C) the commission determines that the generation resource is not required for ERCOT reliability; or

(D) a commission order requiring the generation entity to provide RMR service takes effect.

(3) RMR exit strategy. Unless otherwise ordered by the commission, the implementation of an RMR exit strategy pursuant to ERCOT Protocols is not affected by the filing of a complaint pursuant to this subsection.

(f) Noncompetitive constraints. ERCOT, through its stakeholder process, shall develop and submit for commission oversight and review protocols to mitigate the price effects of congestion on noncompetitive constraints.

(1) The protocols shall specify a method by which noncompetitive constraints may be distinguished from competitive constraints.

(2) Competitive constraints and noncompetitive constraints shall be designated annually prior to the corresponding auction of annual congestion revenue rights. A constraint may be redesignated on an interim basis.

(3) The protocols shall be designed to ensure that a noncompetitive constraint will not be treated as a competitive constraint.

(4) The protocols shall not take effect until after the commission has exercised its oversight and review authority over these protocols as part of the implementation of the requirements of §25.501 of this title, (relating to Wholesale Market Design for the Electric Reliability Council of Texas) so that these protocols shall take effect as part of the wholesale market design required by that section. Any subsequent amendment to these protocols shall also be submitted to the commission for oversight and review, and shall not take effect unless ordered by the commission.

(5) ERCOT, through its stakeholder process, may adopt protocols that categorize all constraints as noncompetitive constraints. Protocols adopted pursuant to this paragraph shall terminate no later than the 45th day after ERCOT begins to use nodal energy prices for resources pursuant to §25.501(f) of this title. Protocols adopted pursuant to this paragraph need not be submitted to the commission for oversight and review prior to taking effect.

§25.503. Oversight of Wholesale Market Participants.

(a) **Purpose**. The purpose of this section is to establish the standards that the commission will apply in monitoring the activities of entities participating in the wholesale electricity markets, including markets administered by the Electric Reliability Council of Texas (ERCOT), and enforcing the Public Utility Regulatory Act (PURA) and ERCOT procedures relating to wholesale markets. The standards contained in this rule are necessary to:

(1) protect customers from unfair, misleading, and deceptive practices in the wholesale markets, including ERCOT-administered markets;

(2) ensure that ancillary services necessary to facilitate the reliable transmission of electric energy are available at reasonable prices;

(3) afford customers safe, reliable, and reasonably priced electricity;

(4) ensure that all wholesale market participants observe all scheduling, operating, reliability, and settlement policies, rules, guidelines, and procedures established in the ERCOT procedures;

(5) clarify prohibited activities in the wholesale markets, including ERCOT-administered markets;

(6) monitor and mitigate market power as authorized by the Public Utility Regulatory Act (PURA) §39.157(a) and prevent market power abuses;

(7) clarify the standards and criteria the commission will use when reviewing wholesale market activities;

(8) clarify the remedies for non-compliance with the Protocols relating to wholesale markets; and

(9) prescribe ERCOT's role in enforcing ERCOT procedures relating to the reliability of the regional electric network and accounting for the production and delivery among generators and all other market participants, and monitoring and obtaining compliance with operating standards within the ERCOT regional network.

(b) **Application. This section applies to all market entities, as defined in subsection (c) of this section.**

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

(1) **Artificial congestion** -- Congestion created when multiple foreseeable options exist for scheduling, dispatching, or operating a resource, and a market participant chooses an option that is not the most economical, that foreseeably creates or exacerbates transmission congestion, and that results in the market participant being paid to relieve the congestion it caused.

(2) **Efficient operation of the market** -- Operation of the markets administered by ERCOT, consistent with reliability standards, that is characterized by the fullest use of competitive auctions to procure ancillary services, minimal cost socialization, and the most economical utilization of resources, subject to necessary operational and other constraints.

(3) **ERCOT procedures** -- Documents that contain the scheduling, operating, planning, reliability, and settlement procedures, standards, and criteria that are public and in effect in the ERCOT power region, including the ERCOT Protocols and ERCOT Operating Guides as amended from time to time but excluding ERCOT's internal administrative procedures. The Protocols generally govern when there are inconsistencies between the Protocols and the Operating Guides, except when ERCOT staff, consistent with subsection (i) of this section, determines that a provision contained in the Operating Guides is technically superior for the efficient and reliable operation of the electric network.

(4) **Excess Revenue --** Revenue in excess of the revenue that would have occurred absent a violation of PURA §39.157 or this section.

(5) **Market entity** -- Any person or entity participating in the ERCOT-administered wholesale market, including, but not limited to, a load serving entity (including a municipally owned utility and an electric cooperative,) a power marketer, a transmission and distribution utility, a power generation

company, a qualifying facility, an exempt wholesale generator, ERCOT, and any entity conducting planning, scheduling, or operating activities on behalf of, or controlling the activities of, such market entities.

(6) **Market participant --** A market entity other than ERCOT.

(7) **Resource** -- Facilities capable of providing electrical energy or load capable of reducing or increasing the need for electrical energy or providing short-term reserves into the ERCOT system. This includes generation resources and loads acting as resources (LaaRs).

(d) Standards and criteria for enforcement of ERCOT procedures and PURA. The commission will monitor the activities of market entities to determine if such activities are consistent with ERCOT procedures; whether they constitute market power abuses or are unfair, misleading, or deceptive practices affecting customers; and whether they are consistent with the proper accounting for the production and delivery of electricity among generators and other market participants. When reviewing the activities of a market entity, the commission will consider whether the activity was conducted in a manner that:

(1) adversely affected customers in a material way through the use of unfair, misleading, or deceptive practices;

(2) materially reduced the competitiveness of the market, including whether the activity unfairly impacted other market participants in a way that restricts competition;

(3) disregarded its effect on the reliability of the ERCOT electric system; or

(4) interfered with the efficient operation of the market.

(e) **Guiding ethical standards.** Each market participant is expected to:

(1) observe all applicable laws and rules;

(2) schedule, bid, and operate its resources in a manner consistent with ERCOT procedures to support the efficient and reliable operation of the ERCOT electric system; and

(3) not engage in activities and transactions that create artificial congestion or artificial supply shortages, artificially inflate revenues or volumes, or manipulate the market or market prices in any way.

(f) **Duties of market entities.**

(1) Each market participant shall be knowledgeable about ERCOT procedures.

(2) A market participant shall comply with ERCOT procedures and any official interpretation of the Protocols issued by ERCOT or the commission.

(A) If a market participant disagrees with any provision of the Protocols or any official interpretation of the Protocols, it may seek an amendment of the Protocols as provided for in the Protocols, appeal an ERCOT official interpretation to the commission, or both.

(B) A market participant appealing an official interpretation of the Protocols or seeking an amendment to the Protocols shall comply with the Protocols unless and until the interpretation is officially changed or the amendment is officially adopted.

(C) A market participant may be excused from compliance with ERCOT instructions or Protocol requirements only if such non-compliance is due to communication or equipment failure beyond the reasonable control of the market participant; if compliance would jeopardize public health and safety or the reliability of the ERCOT transmission grid, or create risk of bodily harm or damage to the equipment; if compliance would be inconsistent with facility licensing, environmental, or legal requirements; if required by applicable law; or for other good cause. A market participant is excused under this subparagraph only for so long as the condition continues.

(3) Whenever the Protocols require that a market participant make its “best effort” or a “good faith effort” to meet a requirement, or similar language, the market participant shall act in accordance with the requirement unless:

(A) it is not technically possible to do so;

(B) doing so would jeopardize public health and safety or the reliability of the ERCOT transmission grid, or would create a risk of bodily harm or damage to the equipment;

(C) doing so would be inconsistent with facility licensing, environmental, or legal requirements; or

(D) other good cause exists for excusing the requirement.

(4) When a market participant is not able to comply with a Protocol requirement or official interpretation of a requirement, or honor a formal commitment to ERCOT, the market participant has an obligation to notify ERCOT immediately upon learning of such constraints and to notify ERCOT when the problem ceases. A market participant who does not comply with a Protocol requirement or official interpretation of a requirement, or honor a formal commitment to ERCOT, has the burden to demonstrate, in any commission proceeding in which the failure to comply is raised, why it cannot comply with the Protocol requirement or official interpretation of the requirement, or honor the commitment.

(5) The commission staff may request information from a market participant concerning a notification of failure to comply with a Protocol requirement or official interpretation of a requirement, or honor a formal commitment to ERCOT. The market participant shall provide a response that is detailed and reasonably complete, explaining the circumstances surrounding the alleged failure, and shall provide documents and other materials relating to such alleged failure to comply. The response shall be submitted to the commission staff within five business days of a written request for information, unless commission staff agrees to an extension.

(6) A market participant's bids of energy and ancillary services shall be from resources that are available and capable of performing, and shall be feasible within the limits of the operating characteristics indicated in the resource plan, as defined in the Protocols, and consistent with the applicable ramp rate, as specified in the Protocols.

(7) All statements, data and information provided by a market participant to market publications and publishers of surveys and market indices for the computation of an industry price index shall be true, accurate, reasonably complete, and shall be consistent with the market participant's activities, subject to generally accepted standards of confidentiality and industry standards. Market participants shall exercise due diligence to prevent the release of materially inaccurate or misleading information.

(8) A market entity has an obligation to provide accurate and factual information and shall not submit false or misleading information, or omit material information, in any communication with ERCOT or with the commission. Market entities shall exercise due diligence to ensure adherence to this provision throughout the entity.

(9) A market participant shall comply with all reporting requirements governing the availability and maintenance of a generating unit or transmission facility, including outage scheduling reporting requirements. A market participant shall immediately notify ERCOT when capacity changes or resource limitations occur that materially affect the availability of a unit or facility, the anticipated operation of its resources, or the ability to comply with ERCOT dispatch instructions.

(10) A market participant shall comply with requests for information or data by ERCOT as specified by the Protocols or ERCOT instructions within the time specified by ERCOT instructions, or such other time agreed to by ERCOT and the market participant.

(11) When a Protocol provision or its applicability is unclear, or when a situation arises that is not contemplated under the Protocols, a market entity seeking clarification of the Protocols shall use the Protocol Revision Request (PRR) process provided in the Protocols. If the PRR process is impractical or inappropriate under the circumstances, the market entity may use the process for requesting formal Protocol clarifications or interpretations described in subsection (i) of this section. This provision is not intended to discourage day to day informal communication between market participants and ERCOT staff.

(12) A market participant operating in the ERCOT markets or a member of the ERCOT staff who identifies a provision in the ERCOT procedures that produces an outcome inconsistent with the

efficient and reliable operation of the ERCOT-administered markets shall call the provision to the attention of ERCOT staff and the appropriate ERCOT subcommittee. All market participants shall cooperate with the ERCOT subcommittees, ERCOT staff, and the commission staff to develop Protocols that are clear and consistent.

(13) A market participant shall establish and document internal procedures that instruct its affected personnel on how to implement ERCOT procedures according to the standards delineated in this section. Each market participant shall establish clear lines of accountability for its market practices.

(g) **Prohibited activities.** Any act or practice of a market participant that materially and adversely affects the reliability of the regional electric network or the proper accounting for the production and delivery of electricity among market participants is considered a "prohibited activity." The term "prohibited activity" in this subsection excludes acts or practices expressly allowed by the Protocols or by official interpretations of the Protocols and acts or practices conducted in compliance with express directions from ERCOT or commission rule or order or other legal authority. The term "prohibited activity" includes, but is not limited to, the following acts and practices that have been found to cause prices that are not reflective of competitive market forces or to adversely affect the reliability of the electric network:

(1) A market participant shall not schedule, operate, or dispatch its generating units in a way that creates artificial congestion.

(2) A market participant shall not execute pre-arranged offsetting trades of the same product among the same parties, or through third party arrangements, which involve no economic risk and no material net change in beneficial ownership.

(3) A market participant shall not offer reliability products to the market that cannot or will not be provided if selected.

(4) A market participant shall not conduct trades that result in a misrepresentation of the financial condition of the organization.

(5) A market participant shall not engage in fraudulent behavior related to its participation in the wholesale market.

(6) A market participant shall not collude with other market participants to manipulate the price or supply of power, allocate territories, customers or products, or otherwise unlawfully restrain competition. This provision should be interpreted in accordance with federal and state antitrust statutes and judicially-developed standards under such statutes regarding collusion.

(7) A market participant shall not engage in market power abuse. Withholding of production, whether economic withholding or physical withholding, by a market participant who has market power, constitutes an abuse of market power.

(h) **Defenses.** The term "prohibited activity" in subsection (g) of this section excludes acts or practices that would otherwise be included, if the market entity establishes that its conduct served a legitimate business purpose consistent with prices set by competitive market forces; and that it did not know, and could not reasonably anticipate, that its actions would inflate prices, adversely affect the reliability of the regional electric network, or adversely affect the proper accounting for the production and delivery of electricity; or, if applicable, that it exercised due diligence to prevent the excluded act or practice. The defenses established in this subsection may also be asserted in instances in which a market participant is alleged to have violated subsection (f) of this section. A market entity claiming an exclusion or defense under this subsection, or any other type of affirmative defense, has the burden of proof to establish all of the elements of such exclusion or defense.

(i) **Official interpretations and clarifications regarding the Protocols.** A market entity seeking an interpretation or clarification of the Protocols shall use the PRR process contained in the Protocols whenever possible. If an interpretation or clarification is needed to address an unforeseen situation and there is not sufficient time to submit the issue to the PRR process, a market entity may seek an official Protocol interpretation or clarification from ERCOT in accordance with this subsection.

(1) ERCOT shall develop a process for formally addressing requests for clarification of the Protocols submitted by market participants or issuing official interpretations regarding the application of Protocol provisions and requirements. ERCOT shall respond to the requestor within ten business days of ERCOT's receipt of the request for interpretation or clarification with either an official Protocol interpretation or a recommendation that the requestor take the request through the PRR process.

(2) ERCOT shall designate one or more ERCOT officials who will be authorized to receive requests for clarification from, and issue responses to market participants, and to issue official interpretations on behalf of ERCOT regarding the application of Protocol provisions and requirements.

(3) The designated ERCOT official shall provide a copy of the clarification request to commission staff upon receipt. The ERCOT official shall consult with ERCOT operational or legal staff as appropriate and with commission staff before issuing an official Protocol clarification or interpretation.

(4) The designated ERCOT official may decide, in consultation with the commission staff, that the language for which a clarification is requested is ambiguous or for other reason beyond ERCOT's ability to clarify, in which case the ERCOT official shall inform the requestor, who may take the request through the PRR process provided for in the Protocols.

(5) All official Protocol clarifications or interpretations that ERCOT issues in response to a market participant's formal request or upon ERCOT's own initiative shall be sent out in a market bulletin with the appropriate effective date specified to inform all market participants, and a copy of the clarification or interpretation shall be maintained in a manner that is accessible to market participants. Such response shall not contain information that would identify the requesting market participant.

(6) A market participant may freely communicate informally with ERCOT employees, however, the opinion of an individual ERCOT staff member not issued as an official interpretation of ERCOT pursuant to this subsection may not be relied upon as an affirmative defense by a market participant.

(j) **Role of ERCOT in enforcing operating standards.** ERCOT shall develop and submit for commission approval a process to monitor material occurrences of non-compliance with ERCOT procedures, which shall mean occurrences that have the potential to impede ERCOT operations, or represent a risk to system reliability. Non-compliance indicators monitored by ERCOT shall include, but shall not be limited to, material occurrences of schedule control error, failing resource plan performance measures as established by ERCOT, failure to follow dispatch instructions within the required time, failure to meet ancillary services obligations, failure to submit mandatory bids or offers that may apply, and other instances of non-compliance of a similar magnitude.

(1) ERCOT shall keep a record of all such material occurrences of non-compliance with ERCOT procedures and shall develop a system for tracking recurrence of such material occurrences of non-compliance.

(2) ERCOT shall promptly provide information to and respond to questions from market participants to allow the market participant to understand and respond to alleged material occurrences of non-compliance with ERCOT procedures. However, this requirement does not relieve the market participant's operator from responding to the ERCOT operator's instruction in a timely manner and should not be interpreted as allowing the market participant's operator to argue with the ERCOT operator as to the need for compliance.

(3) ERCOT shall keep a record of the resolution of such material occurrences of non-compliance and of remedial actions taken by the market participant in each instance.

(4) ERCOT shall inform the commission staff immediately if the material occurrence of non-compliance is not resolved after the system operator has orally informed the market participant of the problem. The occurrence is not resolved if:

(A) the same instance of non-compliance is repeated more than once in a six-month period; or

(B) the occurrence continues after ERCOT has first orally notified the operator of the market participant, and subsequently notified, orally or in writing, the supervisor of the operator of the market participant.

(k) **Standards for record keeping.**

(1) A market participant who schedules through a qualified scheduling entity (QSE) that submits schedules to ERCOT on behalf of more than one market participants shall maintain records to show scheduling and bidding information for all schedules and bids that its QSE has submitted to ERCOT on its behalf, by interval.

(2) All market participants and ERCOT shall maintain records relative to market participants' activities in the ERCOT-administered markets to show:

(A) information on transactions, as defined in §25.93(c)(3) of this title (relating to Quarterly Wholesale Electricity Transaction Reports), including the date, type of transaction, amount of transaction, and entities involved;

(B) information and documentation of all planned and forced generation and transmission outages including all documentation necessary to document the reason for the outage;

(C) information described under this subsection including transaction information, information on pricing, settlement information, and other information that would be relevant to an investigation under this section, and that has been disclosed to market publications and publishers of surveys and price indices, including the date, information disclosed, and the name of the employees involved in providing the information as well as the publisher to whom it was provided; and

(D) reports of the market participant's financial information given to external parties, including the date, financial results reported, and the party to whom financial information was reported, if applicable.

(3) After the effective date of this section, all records referred to in this subsection except verbally dispatch instructions (VDIs) shall be kept for a minimum of three years from the date of the event. ERCOT shall keep VDI records for a minimum of two years. All records shall be made available to the commission for inspection upon request.

(4) A market participant shall, upon request from the commission, provide the information referred to in this subsection to the commission, and may, if applicable, provide it under a confidentiality agreement or protective order pursuant to §22.71(d) of this title (relating to Filing of Pleadings, Documents, and Other Material).

(l) **Investigation.** The commission staff may initiate an informal fact-finding review based on a complaint or upon its own initiative to obtain information regarding facts, conditions, practices, or matters that it may find necessary or proper to ascertain in order to evaluate whether any market entity has violated any provision of this section**.**

(1) The commission staff will contact the market entity whose activities are in question to provide the market entity an opportunity to explain its activities. The commission staff may require the market entity to provide information reasonably necessary for the purposes described in this subsection.

(2) If the market entity asserts that the information requested by commission staff is confidential, the information shall be provided to commission staff as confidential information related to settlement negotiations or other asserted bases for confidentiality pursuant to §22.71(d)(4) of this title.

(3) If after conducting its fact-finding review, the commission staff determines that a market entity may have violated this section, the commission staff may request that the commission initiate a

formal investigation against the market entity pursuant to §22.241 of this title (relating to Investigations).

(4) If, as a result of its investigation, commission staff determines that there is evidence of a violation of this section by a market entity, the commission staff may request that the commission initiate appropriate enforcement action against the market entity. A notice of violation requesting administrative penalties or disgorgement of excess revenues shall comply with the requirements of §22.246 of this title (relating to Administrative Penalties). Adjudication of a notice of violation requesting both an administrative penalty and disgorgement of excess revenues may be conducted within a single contested case proceeding. Additionally, for alleged violations that have been reviewed in the informal procedure established by this subsection, the commission staff shall include as part of its prima facie case:

(A) a statement either that –

(i) the commission staff has conducted the investigation allowed by this section; or

(ii) the market participant has failed to comply with the requirements of paragraph (5) of this subsection;

(B) a summary of the evidence indicating to the commission staff that the market participant has violated one of the provisions of this section;

(C) a summary of any evidence indicating to the commission staff that the market participant benefited from the alleged violation or materially harmed the market; and

(D) a statement that the staff has concluded that the market participant failed to demonstrate, in the course of the investigation, the applicability of an exclusion or affirmative defense under subsection (h) of this section.

(5) A market entity subject to an informal fact-finding review or a formal investigation by the commission has an obligation to fully cooperate with the investigation, to make its company representatives available within a reasonable period of time to discuss the subject of the investigation with the commission staff, and to respond to the commission staff's requests for information within a reasonable time frame as requested by the commission staff.

(6) The procedure for informal fact-finding review established in this subsection does not prevent any person or commission staff from filing a formal complaint with the commission pursuant to §22.242 of this title (relating to Complaints) or pursuing other relief available by law.

(m) **Remedies.** If the commission finds that a market entity is in violation of this section, the commission may seek or impose any legal remedy it determines appropriate for the violation involved, provided that the remedy of disgorgement of excess revenues shall be imposed for violations and continuing violations of PURA §39.157 and may be imposed for other violations of this section.

§25.504. Wholesale Market Power in the Electric Reliability Council of Texas Power Region.

(a) **Application**. This section applies to all generation entities in the Electric Reliability Council of Texas (ERCOT). This section defines the term "market power," as that term is used in §25.503 of this title (relating to Oversight of Wholesale Market Participants).

(b) **Definitions**. The following terms, when used in this section, shall have the following meanings, unless the context or specific language of a section indicates otherwise:

(1) **Generation entity –** An entity that controls a generation resource. An entity affiliated with a generation entity shall be considered part of that generation entity.

(2) **Market power –** The ability to control prices or exclude competition in a relevant market.

(3) **Market power abuse –** Practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition, including practices that tie unregulated products or services to regulated products or services or unreasonably discriminate in the provision of regulated services. Market power abuses include predatory pricing, withholding of production, precluding entry, and collusion.

(c) **Exemption based on installed generation capacity**. A single generation entity that controls less than 5% of the installed generation capacity in ERCOT, as the term "installed generation capacity" is defined in §25.5 of this title (relating to Definitions), excluding uncontrollable renewable resources, is deemed not to have ERCOT-wide market power. Controlling 5% or more of the installed generation capacity in ERCOT does not, of itself, mean that a generating entity has market power.

(d) **Withholding of production**. Prices offered by a generation entity with market power may be a factor in determining whether the entity has withheld production. A generation entity with market power that prices its services substantially above its marginal cost may be found to be withholding production; offering prices that are not substantially above marginal cost does not constitute withholding of production.

(e) **Voluntary mitigation plan**. Any generation entity may submit to the commission a mitigation plan for ensuring compliance with §25.503(g)(7) of this title or with the Public Utility Regulatory Act §39.157(a). Any plan that is submitted may be revised, with the agreement of the market participant, and approved or rejected by the commission. Adherence to a plan approved by the commission constitutes an absolute defense against an allegation of market power abuse with respect to behaviors addressed by the plan. Failure to adhere to a plan approved by the commission does not, of itself constitute a violation of §25.503(g)(7) of this title, but may be treated in the same manner as any other violation of a commission order.

§25.505. Resource Adequacy in the Electric Reliability Council of Texas Power Region.

(a) **General.** The purpose of this section is to prescribe mechanisms that the Electric Reliability Council of Texas (ERCOT) shall establish to provide for resource adequacy in the energy-only market design that applies to the ERCOT power region. The mechanisms are intended to encourage market participants to build and maintain a mix of resources that sustain adequate supply of electric service in the ERCOT power region, and to encourage market participants to take advantage of practices such as hedging, long-term contracting between market participants that supply power and market participants that serve load, and price responsiveness by end-use customers.

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

(1) **Generation entity** -- an entity that owns or controls a generation resource.

(2) **Event trigger --** a calculated value for each interval that is equal to 50 times the Houston Ship Channel natural gas price index for each operating day, expressed in dollars per megawatt-hour (MWh) or dollars per megawatt per hour (MW/h). The event trigger shall be applied solely for the purpose of establishing the timing of the publication of certain market data and shall not be construed to establish the legitimacy of any offer, whether such offer is less than, equal to, or higher than the event trigger.

(3) **Load entity --** an entity that owns or controls a load resource, including, but not limited to, a load acting as a resource (LaaR) or a balancing up load (BUL), as those terms are defined in the ERCOT Protocols.

(4) **Resource entity --** an entity that is a generation entity or a load entity.

(c) **Statement of opportunities (SOO).** ERCOT shall publish a SOO that provides market participants with a projection of the capability of existing and planned electric generation resources, load resources, and transmission facilities to reliably meet ERCOT's projected needs. A SOO published in even-numbered years shall use a ten-year study horizon and be published by December 31 of those years. A SOO published in odd-numbered years shall use a five-year study horizon and be published on or around October 1 of those years. ERCOT shall prescribe reporting requirements for generation entities and transmission service providers (TSPs) to report to ERCOT their plans for adding new facilities, upgrading existing facilities, and mothballing or retiring existing facilities. ERCOT also shall prescribe reporting requirements for load entities to report to ERCOT their plans for adding new load resources or retiring existing load resources.

(d) **Projected assessment of system adequacy (PASA).** Beginning no later than October 1, 2006, unless otherwise specified below, ERCOT shall provide market participants with information to assess the adequacy of resources and transmission facilities to meet projected demand in the following two reports:

(1) Each month, ERCOT shall publish a Medium-Term PASA for each week of the subsequent three years beginning with the week after the Medium-Term PASA is published. At a minimum, each Medium-Term PASA shall include the following information:

(A) Load forecast by ERCOT zone or area;

(B) Ancillary service requirements;

(C) Transmission constraints; and

(D) Aggregated information on the availability of resources, by ERCOT zone or area, including load resources.

(2) Each day, ERCOT shall publish a Short-Term PASA for each hour for the seven days beginning with the day the Short-Term PASA is published.

(A) At a minimum, each Short-Term PASA shall include the following information:

(i) Load forecast by ERCOT zone or area;

(ii) Ancillary service requirements;

(iii) Transmission constraints; and

(iv) Aggregated information on the availability of resources, by ERCOT zone or area, including load resources.

(B) By October 1, 2006, ERCOT shall file at the commission a plan to incorporate the impact of transmission constraints into its Short-Term PASA at a later date.

(e) **Filing of resource and transmission information with ERCOT.** ERCOT shall prescribe reporting requirements for resource entities and TSPs for the preparation of PASAs. At a minimum, the following information shall be reported to ERCOT:

(1) TSPs shall provide ERCOT with information on planned and existing transmission outages.

(2) Generation entities shall provide ERCOT with information on planned and existing generation outages.

(3) Load entities shall provide ERCOT with information on planned and existing availability of LaaRs, specified by type of ancillary service, and BULs.

(4) Generation entities shall provide ERCOT with a complete list of generation resource availability and performance capabilities, including, but not limited to:

(A) the net dependable capability of generation resources;

(B) projected output of non-dispatchable resources such as wind turbines, run-of-the-river hydro, and solar power; and

(C) output limitations on generation resources that result from fuel or environmental restrictions.

(5) Load serving entities (LSEs) shall provide ERCOT with complete information on load response capabilities that are self-arranged or pursuant to bilateral agreements between LSEs and their customers.

(f) **Publication of resource and load information in ERCOT markets.** To increase the transparency of the ERCOT-administered markets, ERCOT shall post at a publicly accessible location on its website, beginning no later than October 1, 2006, the information required pursuant to this subsection, unless a different date is specified by a paragraph of this subsection.

(1) The following information in aggregated form, for each settlement interval and for each area where available, shall be posted two calendar days after the day for which the information is accumulated.

(A) Quantities and prices of offers for energy and each type of ancillary capacity service, in the form of supply curves.

(B) Self-arranged energy and ancillary capacity services, for each type of service.

(C) Actual resource output.

(D) Load and resource output for all entities that dynamically schedule their resources.

(E) During the operation of the market under a zonal market design, scheduled load and actual load. During the operation of the market under a nodal market design, firm scheduled load, scheduled load with “up to” limits on congestion charges, and actual load.

(2) During the operation of the market under a nodal market design, the following day-ahead market information in aggregate form shall be posted two calendar days after the day for which the information is accumulated: load bids, including virtual loads, in the form of day-ahead bid curves, and cleared load.

(3) The following information in entity-specific form, for each settlement interval, shall be posted as specified in subparagraphs (A) - (E) of this paragraph.

(A) During the operation of the market under a zonal market design:

(i) Portfolio offer curves for balancing energy and for each type of ancillary service, for each area where available, shall be posted 60 days after the day for which the information is accumulated beginning September 1, 2007, except that, for the highest-priced offer selected or dispatched by ERCOT for each interval after January 12, 2007, ERCOT shall post the offer price and the name of the entity submitting the offer 48 hours after the day for which the information is accumulated. In the event of interzonal congestion, ERCOT shall post, separately for each zone, the offer price and the name of the entity submitting the highest-priced offer selected or dispatched.

(ii) If the market clearing price for energy (MCPE) or the market clearing price for capacity (MCPC) exceeds the event trigger during any interval, the portion of every market participant's price-quantity offer pair for balancing energy service and each other ancillary service that is at or above the event trigger for that service and that interval shall be posted seven (7) days after the day for which the offer is submitted. ERCOT shall implement the requirements of this clause by September 1, 2007.

(iii) Other offer-specific information for each type of service and for each area where available shall be posted 90 days after the day for which the information is accumulated beginning March 1, 2007. Effective March 1, 2008, this information shall be posted 60 days after the day the information was accumulated. The information subject to this disclosure requirement is as follows:

(I) final energy schedules for each QSE;

(II) final ancillary services schedules for each QSE;

(III) resource plans for each QSE representing a resource;

(IV) actual output from each resource; and

(V) all dispatch instructions from ERCOT for balancing energy and ancillary services.

(iv) The information posted shall include the names of the resources in the portfolio that were committed, the name of the entity submitting the information, the name of the entity controlling each resource in the portfolio.

(B) Two months after the start of operation of the market under a nodal market design:

(i) Offer curves (prices and quantities) for each type of ancillary service and for energy at each settlement point in the real time market, shall be posted 60 days after the day for which the information is accumulated except that, for the highest-priced offer selected or dispatched for each interval on an ERCOT-wide basis, ERCOT shall post the offer price and the name of the entity submitting the offer 48 hours after the day for which the information is accumulated.

(ii) If the MCPE or the MCPC exceeds the event trigger during any interval, the portion of every market participant's price-quantity offer pairs for balancing energy service and each other ancillary service that is at or above the event trigger for that service and that interval shall be posted seven (7) days after the day for which the offer is submitted.

(iii) Other resource-specific information, as well as self-arranged energy and ancillary capacity services, and actual resource output, for each type of service and for each resource at each settlement point shall be posted 60 days after the day for which the information is accumulated.

(iv) The posted information shall be linked to the name of the resource (or identified as a virtual offer), the name of the entity submitting the information, and the name of the entity controlling the resource. If there are multiple offers for the resource, ERCOT shall post the specified information for each offer for the resource, including the name of the entity submitting the offer and the name of the entity controlling the resource.

(C) The load and generation resource output for each zone, for each entity that dynamically schedules its resources, shall be posted 90 days after the day for which the information is accumulated beginning March 1, 2007. Effective March 1, 2008, the information required by this subparagraph shall be posted 60 days after the day for which the information is accumulated.

(D) ERCOT shall use §25.502(d) of this title (relating to Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas) as a basis for determining the control of a resource and shall include this information in its market operations data system.

(E) After the start of operation of the market under a nodal market design, ERCOT shall begin posting transmission flows, voltages, transformer flows, voltages and tap positions (i.e., State Estimator data) 60 days after the day for which the data were accumulated or other time interval as established in clause (ii) of this subparagraph. The data released shall be made available simultaneously to all market participants.

(i) Notwithstanding the provisions of this subparagraph and the provisions of subparagraph (B) of this paragraph, ERCOT, in its sole discretion, shall release relevant State Estimator data earlier than 60 days after the day for which the information is accumulated if it determines the release is necessary to provide a complete and timely explanation and analysis of unexpected market operations and results or system events, including but not limited to pricing anomalies, recurring transmission congestion, and system disturbances. ERCOT's release of data under this clause shall be limited to intervals associated with the unexpected market or system event as determined by ERCOT. The data released shall be made available simultaneously to all market participants.

(ii) Notwithstanding the provisions of this subparagraph and the other provisions of subparagraph (B) of this paragraph, ERCOT shall, by the start of the nodal market, develop and post a redacted version of State Estimator data, as soon as reasonably practicable after collection of the data, so long as a redacted version excludes information (including but not limited to, voltages, transmission flows and transformer flows) from which resource-specific output levels or offer curves could continually and systematically be derived. Concurrently, in conjunction with the Independent Market Monitor and the commission Staff, ERCOT, through its stakeholder process, shall develop protocols that detail, at a minimum, the methodology, duration, and posting requirement of a redacted version of the State Estimator data. The redacted report methodology developed through the stakeholder process shall be completed within 90 days of the start of the nodal market. If ERCOT is unable to develop a cost effective protocol for the redaction process of the State Estimator data within 90 days of the start of the nodal market, then the following information shall be released as soon as reasonably practicable:

(I) Current commercially significant constraints (CSCs) and closely related elements (CREs) line flows that are embodied in the competitive constraint list from the Competitive Constraint Test;

(II) For phase shifting transformers, tap positions and line flows;

(III) Voltages at all buses;

(IV) Line flows on lines that make up interfaces (import, export, flow gate, or stability); and

(V) Line flows on DC ties.

(iii) In no event shall ERCOT disclose competitively sensitive consumption data.

(g) **Scarcity pricing mechanism (SPM).** ERCOT shall administer the SPM. The SPM shall operate as follows:

(1) The SPM shall operate on an annual resource adequacy cycle, starting on January 1 and ending on December 31 of each year.

(2) For each day of the annual resource adequacy cycle, the peaking operating cost (POC) shall be 10 times the daily Houston Ship Channel gas price index for the previous business day. The POC is calculated in dollars per megawatt-hour (MWh).

(3) For the purpose of this section, the real-time energy price (RTEP) shall be measured as the price at an ERCOT-calculated ERCOT-wide hub.

(4) In the annual resource adequacy cycle, the peaker net margin (PNM) shall be calculated as: ∑((RTEP – POC) * (number of minutes in a settlement interval / 60 minutes per hour)) for each settlement interval when RTEP – POC >0.

(5) Each day ERCOT shall post at a publicly accessible location on its website the updated value of the PNM, in dollars per megawatt (MW).

(6) The system-wide offer caps shall be as follows:

(A) The low system-wide offer cap (LCAP) shall be set on a daily basis at the higher of:

(i) $2,000 per MWh and $2,000 per MW per hour; or

(ii) 50 times the daily Houston Ship Channel gas price index of the previous business day, expressed in dollars per MWh and dollars per MW per hour.

(B) The high system-wide offer cap (HCAP) shall be set:

(i) Beginning on June 1, 2013 at $5,000 per MWh and $5,000 per MW per hour.

(ii) Beginning on June 1, 2014 at $7,000 per MWh and $7,000 per MW per hour.

(iii) Beginning on June 1, 2015 at $9,000 per MWh and $9,000 per MW per hour.

(C) At the beginning of the annual resource adequacy cycle, the system-wide offer cap shall be set equal to the HCAP and, except for increases authorized in this section, maintained at this level as long as the PNM during an annual resource adequacy cycle is less than or equal to a threshold of $300,000 per MW in 2012 and 2013, or the threshold set by ERCOT for a subsequent year. For 2014 and each subsequent year, ERCOT shall set the PNM threshold at three times the cost of new entry of new generation plants. During an annual resource adequacy cycle, the system-wide offer cap shall be increased in accordance with the schedule authorized in this section unless the PNM threshold has been exceeded by that date. If the PNM threshold has been exceeded during an annual resource adequacy schedule, the system-wide offer cap shall be reset at the LCAP for the remainder of that annual resource adequacy cycle.

(D) The Independent Market Monitor, as part of its responsibilities pursuant to Public Utility Regulatory Act §39.1515(h), may conduct an annual review of the effectiveness of the SPM.

(h) **Development and implementation.** ERCOT shall use a stakeholder process to develop protocols that comply with this section. Nothing in this section prevents the commission from taking actions necessary to protect the public interest, including actions that are otherwise inconsistent with the other provisions in this section.

§25.507. Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS).

(a) **Purpose**. The purpose of this section is to promote reliability during energy emergencies through provisions that provide ERCOT flexibility in the implementation and administration of ERS.

(b) **ERS procurement.** ERCOT shall procure ERS, a special emergency response service that is intended to be deployed by ERCOT in an Energy Emergency Alert (EEA) event.

- (1) ERCOT shall determine the ERS contract periods during which ERS resources shall be obligated to provide ERS, including any additional ERS contract periods ERCOT deems necessary due to the depletion of available ERS.
- (2) ERCOT may spend a maximum of $50 million per calendar year on ERS. ERCOT may determine cost limits for each ERS contract period in order to ensure that the ERS cost cap is not exceeded. To minimize the cost of ERS, ERCOT may reject any offer that ERCOT determines to be unreasonable or outside of the parameters of an acceptable offer. ERCOT may also reject any offer placed on behalf of any ERS resource if ERCOT determines that it lacks a sufficient basis to verify whether the ERS resource complied with ERCOT-established performance standards in an ERS deployment event during the preceding ERS contract period.

(c) **Definitions.**

- (1) ERS contract period -- A period defined by ERCOT for which an ERS resource is obligated to provide ERS.
- (2) ERS resource -- A resource contracted to provide ERS that meets one of the following descriptions:
  - (A) A load or aggregation of loads; or
  - (B) A dispatchable generator that is not registered with ERCOT as a Generation Resource, or an aggregation of such generators.
- (3) ERS time period -- Sets of hours designated by ERCOT within an ERS contract period.
- (4) ERCOT -- The staff of the Electric Reliability Council of Texas, Inc.

(d) **Participation in ERS**. In addition to requirements established by ERCOT, the following requirements shall apply for the provision of ERS:

- (1) An ERS resource must be represented by a qualified scheduling entity (QSE).
- (2) QSEs shall submit offers to ERCOT on behalf of their ERS resources.
  - (A) Offers may be submitted for one or more ERS time periods within an ERS contract period.
  - (B) QSEs representing ERS resources may aggregate multiple loads to reach the minimum capacity offer requirement established by ERCOT. Such aggregations shall be considered a single ERS resource for purposes of submitting offers.
- (3) ERCOT shall establish qualifications for QSEs and ERS resources to participate in ERS.
- (4) A resource shall not commit to provide ERS if it is separately obligated to provide response with the same capacity during any of the same hours.
- (5) ERCOT shall establish performance criteria for QSEs and ERS resources.
- (6) When dispatched by ERCOT, ERS resources shall deploy consistent with their obligations and shall remain deployed until recalled by ERCOT.
- (7) ERCOT may deploy ERS resources as necessary, subject to the annual expenditure cap. Deployment of an ERS resource shall be limited to a maximum of eight cumulative hours in an ERS contract period. However, if an instruction causes the cumulative total ERS deployment time to exceed eight hours within a contract period, each ERS resource shall remain deployed until permitted by ERCOT procedures or by ERCOT instructions to return from deployment.

(8) Upon exhaustion of an ERS resource's obligation in any contract period, ERCOT shall have the option to renew that obligation, subject to the consent of the ERS resource and its QSE. ERCOT may renew the obligation on each occasion that the resource's obligation is exhausted.

(9) ERCOT shall establish procedures for testing of ERS resources.

(10) A resource with a pre-existing contract to provide ERS may submit a proposal to serve as an alternative to a resource subject to reliability must-run (RMR) service for the same period. If the resource is selected, ERCOT shall appropriately modify or terminate the resource's pre-existing ERS contract to allow the resource to participate as an RMR alternative.

(e) **ERS Payment and Charges**.

(1) ERCOT shall make a payment to each QSE representing an ERS resource on an as-bid basis, a market clearing price mechanism, or such other mechanism as ERCOT deems appropriate, subject to modifications determined by ERCOT based on the ERS resource's availability during an ERS contract period and the ERS resource's performance in any deployment event.

(2) ERCOT shall charge each QSE a charge for ERS based upon its load ratio share during the relevant ERS time period and ERS contract period.

(3) ERCOT shall settle an ERS contract period within 80 days following the completion of the ERS contract period.

(f) **Compliance**. A QSE representing ERS resources is subject to administrative penalties for noncompliance, by the QSE or the ERS resources it represents, with this rule or any related ERCOT Protocols, Operating Guides, or other ERCOT standards. ERCOT shall establish criteria for reducing a QSE's payment and/or suspending a QSE from participation in ERS for failure to meet its ERS obligations, and shall also establish criteria for subsequent reinstatement. In addition, ERCOT shall establish criteria under which an ERS resource shall be suspended for non-compliance, and shall also establish criteria for subsequent reinstatement. ERCOT shall notify the commission of all instances of non-compliance with this rule or any related ERCOT Protocols, Operating Guides, or other ERCOT standards. ERCOT shall maintain records relating to the alleged non-compliance.

(g) **Reporting**. Prior to the start of an ERS contract period, ERCOT shall report publicly the number of megawatts (MW) procured per ERS time period, the number and type of ERS resources providing the service, and the projected total cost of the service for that ERS contract period. ERCOT shall review the effectiveness and benefits of ERS and report its findings to the commission annually by April 15 of each calendar year. The report shall contain, at a minimum, the number of MW procured in each period, the total dollar amount spent, the number and level of EEA events, and the number and duration of deployments.

(h) **Implementation**. ERCOT shall develop additional procedures, guides, technical requirements, protocols, and/or other standards that are consistent with this section and that ERCOT finds necessary to implement ERS, including but not limited to developing a standard form ERS Agreement and specific performance guidelines and grace periods for ERS resources.

(i) **Self Provision**. ERCOT shall establish procedures for self-provision of ERS by any QSE.

§25.508. High System-Wide Offer Cap in the Electric Reliability Council of Texas Power Region.

Notwithstanding §25.505 of this title (relating to Resource Adequacy in the Electric Reliability Council of Texas Power Region), the high system-wide offer cap shall be $4,500 per megawatt-hour and $4,500 per megawatt per hour beginning on August 1, 2012 and ending on the effective date of any amendment to the high system-wide offer cap in §25.505 of this title that is effective after the effective date of this section.