UTILITIES CODE

TITLE 2. PUBLIC UTILITY REGULATORY ACT

SUBTITLE B. ELECTRIC UTILITIES

CHAPTER 39. RESTRUCTURING OF ELECTRIC UTILITY INDUSTRY

SUBCHAPTER A. GENERAL PROVISIONS

Sec. 39.001. LEGISLATIVE POLICY AND PURPOSE. (a) The legislature finds that the production and sale of electricity is not a monopoly warranting regulation of rates, operations, and services and that the public interest in competitive electric markets requires that, except for transmission and distribution services and for the recovery of stranded costs, electric services and their prices should be determined by customer choices and the normal forces of competition. As a result, this chapter is enacted to protect the public interest during the transition to and in the establishment of a fully competitive electric power industry.

(b) The legislature finds that it is in the public interest to:

(1) implement on January 1, 2002, a competitive retail electric market that allows each retail customer to choose the customer's provider of electricity and that encourages full and fair competition among all providers of electricity;

(2) allow utilities with uneconomic generation-related assets and purchased power contracts to recover the reasonable excess costs over market of those assets and purchased power contracts;

(3) educate utility customers about anticipated changes in the provision of retail electric service to ensure that the benefits of the competitive market reach all customers; and

(4) protect the competitive process in a manner that ensures the confidentiality of competitively sensitive information during the transition to a competitive market and after the commencement of customer choice.

(c) Regulatory authorities, excluding the governing body of a municipally owned electric utility that has not opted for customer choice or the body vested with power to manage and operate a municipally owned electric utility that has not opted for customer choice, may not make rules or issue orders regulating competitive electric services, prices, or competitors or restricting or conditioning competition except as authorized in this title and may not discriminate against any participant or type of participant during the transition to a competitive market and in the competitive market.

(d) Regulatory authorities, excluding the governing body of a municipally owned electric utility that has not opted for customer choice or the body vested with power to manage and operate a municipally owned electric utility that has not opted for customer choice, shall authorize or order competitive rather than regulatory methods to achieve the goals of this chapter to the greatest extent feasible and shall adopt rules and issue orders that are both practical and limited so as to impose the least impact on competition.

(e) Judicial review of competition rules adopted by the commission shall be conducted under Chapter 2001, Government Code, except as otherwise provided by this chapter. Judicial review of the validity of competition rules shall be commenced in the Court of Appeals for the Fifteenth Court of Appeals District and shall be limited to the commission's rulemaking record. The rulemaking record consists of:

(1) the notice of the proposed rule;

(2) the comments of all interested persons;

(3) all studies, reports, memoranda, or other materials on which the commission relied in adopting the rule; and

(4) the order adopting the rule.

(f) A person who challenges the validity of a competition rule must file a notice of appeal with the court of appeals and serve the notice on the commission not later than the 15th day after the date on which the rule as adopted is published in the Texas Register. The notice of appeal shall designate the person challenging the rule as the appellant and the commission as the appellee. The commission shall prepare the rulemaking record and file it with the court of appeals not later than the 30th day after the date the notice of appeal is served on the commission. The court of appeals shall hear and determine each appeal as expeditiously as possible with lawful precedence over other matters. The appellant, and any person who is permitted by the court to intervene in support of the appellant's claims, shall file and serve briefs not later than the 30th day after the date the commission files the rulemaking record. The commission, and any person who is permitted by the court to intervene in support of the rule, shall file and serve briefs not later than the 60th day after the date the appellant files the appellant's brief. The court of appeals may, on its own motion or on motion of any person for good cause, modify the filing deadlines prescribed by this subsection. The court of appeals shall render judgment affirming the rule or reversing and, if appropriate on reversal, remanding the rule to the commission for further proceedings, consistent with the court's opinion and judgment. The Texas Rules of Appellate Procedure apply to an appeal brought under this section to the extent not inconsistent with this section.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.
Amended by:

Acts 2023, 88th Leg., R.S., Ch. 459 (S.B. 1045), Sec. 1.13, eff. September 1, 2023.

Sec. 39.002. APPLICABILITY. This chapter, other than Sections 39.151, 39.1516, 39.155, 39.157(e), 39.161, 39.162, 39.163, 39.203, 39.9051, 39.9052, and 39.914(e), and Subchapters M and N, does not apply to a municipally owned utility or an electric cooperative. Sections 39.157(e) and 39.203 apply only to a municipally owned utility or an electric cooperative that is offering customer choice. If there is a conflict between the specific provisions of this chapter and any other provisions of this title, except for Chapters 40 and 41, the provisions of this chapter control.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.
Amended by:

Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 19, eff. September 1, 2007.

Acts 2019, 86th Leg., R.S., Ch. 467 (H.B. 4170), Sec. 16.001, eff. September 1, 2019.

Acts 2019, 86th Leg., R.S., Ch. 610 (S.B. 936), Sec. 2, eff. September 1, 2019.

Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 2, eff. June 16, 2021.

Acts 2021, 87th Leg., R.S., Ch. 950 (S.B. 1580), Sec. 2, eff. June 18, 2021.

Reenacted and amended by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 14, eff. September 1, 2023.

Reenacted and amended by Acts 2023, 88th Leg., R.S., Ch. 768 (H.B. 4595), Sec. 22.003(a), eff. September 1, 2023.

Sec. 39.003. CONTESTED CASES. Unless specifically provided otherwise, each commission proceeding under this chapter, other than a rulemaking proceeding, report, notification, or registration, shall be conducted as a contested case and the burden of proof is on the incumbent electric utility.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

SUBCHAPTER B. TRANSITION TO COMPETITIVE RETAIL ELECTRIC MARKET

Sec. 39.051. UNBUNDLING. (a) On or before September 1, 2000, each electric utility shall separate from its regulated utility activities its customer energy services business activities that are otherwise also already widely available in the competitive market.

(b) Not later than January 1, 2002, each electric utility shall separate its business activities from one another into the following units:

(1) a power generation company;

(2) a retail electric provider; and

(3) a transmission and distribution utility.

(c) An electric utility may accomplish the separation required by Subsection (b) 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 and distribution utilities. Notwithstanding any other provision of this chapter, an electric utility that does not have stranded costs described by Section 39.254 and that on September 1, 2005, has not finalized unbundling pursuant to a commission order approving an unbundling plan may also meet the requirements of Subsection (b) for generation facilities existing on September 1, 2005, in the Electric Reliability Council of Texas if it meets and maintains compliance with the following requirements:

(1) the electric utility has no more than 400 megawatts of Texas jurisdictional capacity from generating units within the Electric Reliability Council of Texas that have not been mothballed or retired;

(2) the electric utility has a contract or contracts with separate nonaffiliated companies or separate affiliated companies for the sale of all of the output from its generating units that have not been mothballed or retired with a contract term that is no shorter than 20 years or the life of the generating units, whichever is shorter; and

(3) the electric utility has a separate division within the electric utility for its generation business activities.

(c-1) A separate division described by Subsection (c)(3) is subject to Subsection (d) and, for the purposes of this chapter, is considered a separate affiliated power generation company and a competitive affiliate.

(d) Each electric utility shall unbundle under this section in a manner that provides for a separation of personnel, information flow, functions, and operations, consistent with Section 39.157(d).

(e) Each electric utility shall file with the commission a plan to implement this section by January 10, 2000.

(f) The commission shall adopt the utility's plan for business separation required by Subsection (b), adopt the plan with changes, or reject the plan and require the utility to file a new plan.

(g) Transactions by electric utilities involving sales, transfers, or other disposition of assets to accomplish the purposes of this section are not subject to Section 14.101, 35.034, or 35.035.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2005, 79th Leg., Ch. 413 (S.B. 1668), Sec. 3, eff. June 17, 2005.

Sec. 39.052. FREEZE ON EXISTING RETAIL BASE RATE TARIFFS. (a) Until January 1, 2002, an electric utility shall provide retail electric service within its certificated service area in accordance with the electric utility's retail base rate tariffs in effect on September 1, 1999, including its purchased power cost recovery factor.

(b) During the freeze period, an electric utility may not increase its retail base rates above the rates provided by this section except for losses caused by force majeure as provided by Section 39.055.

(c) Notwithstanding any other provision of this title, during the freeze period the regulatory authority may not reduce the retail base rates of an electric utility, except as may be ordered as stipulated to by an electric utility in a proceeding for which a final order had not been issued by January 1, 1999.

(d) During the freeze period, the retail base rates, overall revenues, return on invested capital, and net income of an electric utility are not subject to complaint, hearing, or determination as to reasonableness.

(e) An electric utility that has a rate proceeding pending before the commission as of January 2, 1999, shall provide service in accordance with the tariffs approved in that proceeding from the date of approval until the end of the freeze period.

(f) Nothing in this section affects the authority of the commission to fulfill its obligations under Section 39.262.

(g) Nothing in this section shall deny a utility its right to have the commission conduct proceedings and issue a final order pertaining to any matter that may be remanded to the commission by a court having jurisdiction, except that the final order may not affect the rates charged to customers during the freeze period but shall be taken into account during the utility's true-up proceeding under Section 39.262.

(h) Nothing in this title shall be construed to prevent an electric utility or a transmission and distribution utility from filing, and the commission from approving, a change in wholesale transmission service rates during the freeze period.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.053. COST RECOVERY ADJUSTMENTS. This subchapter does not limit or alter the ability of an electric utility during the freeze period to revise its fuel factor or to reconcile fuel expenses and to either refund fuel overcollections or surcharge fuel undercollections to customers, as authorized by its tariffs and Sections 36.203 and 36.205.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.054. RETAIL ELECTRIC SERVICE DURING FREEZE PERIOD. (a) An electric utility shall provide retail electric service during the freeze period in accordance with any contract terms applicable to a particular retail customer approved by the regulatory authority and in effect on December 31, 1998.

(b) Nothing in Sections 39.052(c) and (d) shall be construed to restrict any customer's right to complain during the freeze period to the regulatory authority regarding the quality of retail electric service provided by the electric utility or the applicability of an electric utility's particular tariff to the customer.

(c) Nothing in this title shall be construed to restrict an electric utility, voluntarily and at its sole discretion, from offering new services or new tariff options to its customers during the freeze period, consistent with Section 39.051(a).

(d) Any offering of new services or tariff options under this section shall be equal to or greater than an electric utility's long-run marginal cost and may not be unreasonably preferential, prejudicial, discriminatory, predatory, or anticompetitive.

(e) Revenue from any new offering under this section shall be accounted for in a manner consistent with Section 36.007.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.055. FORCE MAJEURE. (a) An electric utility may recover losses resulting from force majeure through an increase in its retail base rates during the freeze period.

(b) Notwithstanding Subchapter C, Chapter 36, the regulatory authority, after a hearing to determine the electric utility's losses from force majeure, shall permit the utility to fully collect any approved force majeure increase through an appropriate customer surcharge mechanism.

(c) For purposes of this section, "force majeure" means a major event or combination of major events, including new or expanded state or federal statutory or regulatory requirements; hurricanes, tornadoes, ice storms, or other natural disasters; or acts of war, terrorism, or civil disturbance, beyond the control of an electric utility that the regulatory authority finds increases the utility's total reasonable and necessary nonfuel costs or decreases the utility's total nonfuel revenues related to the generation and delivery of electricity by more than 10 percent for any calendar year during the freeze period. The term does not include any changes in general economic conditions such as inflation, interest rates, or other factors of general application.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

SUBCHAPTER C. RETAIL COMPETITION

Sec. 39.101. CUSTOMER SAFEGUARDS. (a) Before customer choice begins on January 1, 2002, the commission shall ensure that retail customer protections are established that entitle a customer:

(1) to safe, reliable, and reasonably priced electricity, including protection against service disconnections in an extreme weather emergency as provided by Subsection (h) or in cases of medical emergency or nonpayment for unrelated services;

(2) to privacy of customer consumption and credit information;

(3) to bills presented in a clear format and in language readily understandable by customers;

(4) to the option to have all electric services on a single bill, except in those instances where multiple bills are allowed under Chapters 40 and 41;

(5) to protection from discrimination on the basis of race, color, sex, nationality, religion, or marital status;

(6) to accuracy of metering and billing;

(7) to information in English and Spanish and any other language as necessary concerning rates, key terms and conditions, in a standard format that will permit comparisons between price and service offerings, and the environmental impact of certain production facilities;

(8) to information in English and Spanish and any other language as necessary concerning low-income assistance programs and deferred payment plans; and

(9) to other information or protections necessary to ensure high-quality service to customers.

(b) A customer is entitled:

(1) to be informed about rights and opportunities in the transition to a competitive electric industry;

(2) to choose the customer's retail electric provider consistent with this chapter, to have that choice honored, and to assume that the customer's chosen provider will not be changed without the customer's informed consent;

(3) to have access to providers of energy efficiency services, to on-site distributed generation, and to providers of energy generated by renewable energy resources;

(4) to be served by a provider of last resort that offers a commission-approved standard service package;

(5) to receive sufficient information to make an informed choice of service provider;

(6) to be protected from unfair, misleading, or deceptive practices, including protection from being billed for services that were not authorized or provided;

(7) to have an impartial and prompt resolution of disputes with its chosen retail electric provider and transmission and distribution utility;

(8) to participation in demand response programs

through retail electric providers that offer demand response programs; and

(9) to receive notice from the retail electric provider that serves the customer when the independent organization certified under Section 39.151 for the ERCOT power region issues an emergency energy alert.

(c) A retail electric provider, power generation company, aggregator, or other entity that provides retail electric service may not refuse to provide retail electric or electric generation service or otherwise 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. A retail electric provider, power generation company, aggregator, or other entity that provides retail electric service may not refuse to provide retail electric or electric generation service to a customer because the customer is located in an economically distressed geographic area or qualifies for low-income affordability or energy efficiency services. The commission shall require a provider to comply with this subsection as a condition of certification or registration.

(d) A retail electric provider, power generation company, aggregator, or other entity that provides retail electric service shall submit reports to the commission and the office annually and on request relating to the person's compliance with this section. The commission by rule shall specify the form in which a report must be submitted. A report must include:

(1) information regarding the extent of the person's coverage;

(2) information regarding the service provided, compiled by zip code and census tract; and

(3) any other information the commission or the office considers relevant to determine compliance.

(e) The commission has the authority to adopt and enforce such rules as may be necessary or appropriate to carry out Subsections (a)-(d), including rules for minimum service standards for a retail electric provider relating to customer deposits and the extension of credit, switching fees, levelized billing programs, interconnection and use of on-site generation, termination of service, and quality of service. The commission has jurisdiction over all providers of electric service in enforcing Subsections (a)-(d) and may assess civil and administrative penalties under Section 15.023 and seek civil penalties under Section 15.028.

(f) On or before June 30, 2001, the commission shall modify its current rules regarding customer protections to ensure that at least the same level of customer protection against potential abuses and the same quality of service that exists on December 31, 1999, is maintained in a restructured electric industry.

(g) Compliance with Subsections (a)-(e) by a provider of electric service which is a municipally owned utility shall be administered solely by the governing body of the municipally owned utility, which shall adopt, implement, and enforce, as to the municipally owned utility, rules having the effect of accomplishing the objectives of Subsections (a)-(e). Reports containing the information required by Subsection (d) shall be filed by the municipally owned utility with the governing body.

(h) A retail electric provider, power generation company, aggregator, or other entity that provides retail electric service may not disconnect service to a residential customer during an extreme weather emergency or on a weekend day. The entity providing service shall defer collection of the full payment of bills that are due during an extreme weather emergency until after the emergency is over and shall work with customers to establish a pay schedule for deferred bills. For purposes of this subsection, "extreme weather emergency" means a period 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 reports; or

(2) the National Weather Service issues a heat advisory for any county in the relevant service territory, or when such an advisory has been issued on any one of the previous two calendar days.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2023, 88th Leg., R.S., Ch. 945 (S.B. 1699), Sec. 2, eff. September 1, 2023.

Sec. 39.102. RETAIL CUSTOMER CHOICE. (a) Each retail customer in this state, except retail customers of electric cooperatives and municipally owned utilities that have not opted for customer choice, shall have customer choice on and after January 1, 2002.

(b) The affiliated retail electric provider of the electric utility serving a retail customer on December 31, 2001, may continue to serve that customer until the customer chooses service from a different retail electric provider, an electric cooperative offering customer choice, or a municipally owned utility offering customer choice.

(c) An electric utility that has in effect a systemwide freeze for residential and commercial customers in effect September 1, 1997, extending beyond December 31, 2001, that has been found by a regulatory authority to be in the public interest is not subject to this chapter. At the expiration of the utility's freeze period, the utility shall be subject to this chapter and, at that time, has no claim for stranded cost recovery.

(d) The commission shall oversee the compliance with this chapter by electric utilities that were not subject to this chapter before September 1, 2003, and in so doing shall establish schedules and procedures and require commission approvals as it deems necessary to achieve the objectives of this chapter. This subsection does not apply to an electric utility to which Subsection (c) applies.

(e) In establishing a schedule under Subsection (d), the commission shall consider:

(1) the effect of customer choice on the reliability of service provided by the electric utility;

(2) whether the electric utility's service area is located in more than one power region;

(3) whether any applicable power region has been certified as a qualifying power region under Section 39.152(a);

(4) whether other electric utilities in the power region offer retail customer choice; and

(5) any other relevant factor.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999. Amended by Acts 2003, 78th Leg., ch. 1327, Sec. 2, eff. Sept. 1, 2003.

Sec. 39.1025. LIMITATIONS ON TELEPHONE SOLICITATION. (a) A person may not make or cause to be made a telephone solicitation to a nonresidential electric customer who has given notice to the commission of the customer's objection to receiving telephone solicitations relating to the customer's choice of retail electric providers.

(b) The commission shall establish and provide for the operation of a database to compile a list of nonresidential electric customers who object to receiving telephone solicitations. The commission may operate the database or contract with another entity to operate the database.

(c) A customer shall pay a fee of not more than $5 for inclusion in the database. The commission shall prescribe the amount of the fee.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.
Amended by:

Acts 2005, 79th Leg., Ch. 171 (H.B. 210), Sec. 3, eff. May 27, 2005.

Sec. 39.103. COMMISSION AUTHORITY TO DELAY COMPETITION AND SET NEW RATES. If the commission determines under Section 39.104 that a power region is unable to offer fair competition and reliable service to all retail customer classes on January 1, 2002, the commission shall delay customer choice for the power region and may on or after January 1, 2002, establish new rates for all electric utilities in the power region as provided by Chapter 36.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.104. CUSTOMER CHOICE PILOT PROJECTS. (a) Customer choice pilot projects may be used to allow the commission to evaluate the ability of each power region and electric utility to implement customer choice. However, in a multiply certificated area, an electric utility may not include customers that were served by an electric cooperative or a municipally owned utility on May 1, 1999.

(b) The commission shall require each electric utility to offer customer choice in its service area within this state amounting to five percent of the utility's combined load of all customer classes within this state beginning on June 1, 2001.

(c) The load designated for customer choice under this section shall be distributed among all customer classes of a utility consistent with the purpose of this section and subject to commission approval.

(d) Customers participating in a pilot project under this section may buy electric energy from any retail electric provider certified by the commission under Section 39.352, including an affiliated retail electric provider; provided, however, that a retail electric provider may not participate in a pilot project in the certificated service area served by the electric utility with which it is affiliated.

(e) Each utility operating a pilot project under this section shall charge residential and small commercial customers in accordance with Section 39.052.

(f) The commission may prescribe reporting requirements it considers necessary to evaluate a pilot project consistent with the purpose of this section.

(g) Customers having customer choice under this section shall be billed as provided by Section 39.107.

(h) The commission may prescribe terms and conditions it considers necessary to prohibit anticompetitive practices and to encourage customer choice offered under this section.

(i) Notwithstanding any other provision of this title, a retail electric provider participating in a pilot project under this section is not an electric utility or a retail electric utility.

(j) Twenty percent of the load designated for customer choice under this section shall be initially set aside for aggregated loads.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.105. LIMITATION ON SALE OF ELECTRICITY. (a) After January 1, 2002, a transmission and distribution utility may not sell electricity or otherwise participate in the market for electricity except for the purpose of buying electricity to serve its own needs.

(b) A person or retail electric utility may not provide, furnish, or make available electric service at retail within the certificated service area of an electric cooperative that has not adopted customer choice or a municipally owned utility that has not adopted customer choice. However, this subsection does not prohibit the provision of electric service in multiply certificated service areas to customers of any other retail electric utility.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.106. PROVIDER OF LAST RESORT. (a) The commission shall designate retail electric providers in areas of the state in which customer choice is in effect to serve as providers of last resort.

(b) A provider of last resort shall offer a standard retail service package for each class of customers designated by the commission at a fixed, nondiscountable rate approved by the commission.

(c) A provider of last resort shall provide the standard retail service package to any requesting customer in the territory for which it is the provider of last resort.

(d) The commission shall designate the provider or providers of last resort not later than June 1, 2001.

(e) The commission shall determine the procedures and criteria, which may include the solicitation of bids, for designating a provider or providers of last resort. The commission may redesignate the provider of last resort according to a schedule it considers appropriate.

(f) In the event that no retail electric provider applies to be the provider of last resort for a given area of the state on reasonable terms and conditions, the commission may require a retail electric provider to become the provider of last resort as a condition of receiving or maintaining a certificate under Section 39.352.

(g) In the event that a retail electric provider fails to serve any or all of its customers, the provider of last resort shall offer that customer the standard retail service package for that customer class with no interruption of service to any customer.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.107. METERING AND BILLING SERVICES. (a) On introduction of customer choice in a service area, metering services for the area shall continue to be provided by the transmission and distribution utility affiliate of the electric utility that was serving the area before the introduction of customer choice. Metering services provided to commercial and industrial customers that are required by the independent system operator to have an interval data recorder meter may be provided on a competitive basis.

(b) Metering services provided to residential customers and to nonresidential customers other than those required by the independent system operator to have an interval data recorder meter shall continue to be provided by the transmission and distribution utility affiliate of the electric utility that was serving the area before the introduction of customer choice. Retail electric providers serving residential and nonresidential customers other than those required by the independent system operator to have an interval data recorder meter may request that the transmission and distribution utility provide specialized meters, meter features, or add-on accessories so long as they are technically feasible and generally available in the market and provided that the retail electric provider pays the differential cost of such a meter or accessory. Metering and billing services provided to residential customers shall be governed by the customer safeguards adopted by the commission under Section 39.101. All meter data, including all data generated, provided, or otherwise made available, by advanced meters and meter information networks, shall belong to a customer, including data used to calculate charges for service, historical load data, and any other proprietary customer information. A customer may authorize its data to be provided to one or more retail electric providers under rules and charges established by the commission.

(c) Beginning on the date of introduction of customer choice in a service area, tenants of leased or rented property that is separately metered shall have the right to choose a retail electric provider, an electric cooperative offering customer choice, or a municipally owned utility offering customer choice, and the owner of the property must grant reasonable and nondiscriminatory access to transmission and distribution utilities, retail electric providers, electric cooperatives, and municipally owned utilities for metering purposes.

(d) Beginning on the date of introduction of customer choice in a service area, a transmission and distribution utility, or an electric cooperative or municipally owned utility providing the customer's energy requirements shall bill a customer's retail electric provider for nonbypassable delivery charges as determined under Section 39.201. The retail electric provider or the electric cooperative or municipally owned utility, as appropriate, must pay these charges.

(e) A transmission and distribution utility may bill retail customers at the request of a retail electric provider or, if an electric cooperative or municipally owned utility is providing the customer's energy requirements, at the request of the electric cooperative or municipally owned utility. A transmission and distribution utility that provides billing service on such request shall offer billing service on comparable terms and conditions to those of any such requesting retail electric provider or, as applicable, the electric cooperative or municipally owned utility providing energy requirements to a customer served by the transmission and distribution utility.

(f) Beginning on the date of introduction of customer choice in a service area, any charges for metering and billing services shall comply with rules adopted by the commission relating to nondiscriminatory rates of service.

(g) Metered electric service sold to residential customers on a prepaid basis may not be sold at a price that is higher than the price charged by the provider of last resort.

(h) The commission shall establish a nonbypassable surcharge for an electric utility or transmission and distribution utility to use to recover reasonable and necessary costs incurred in deploying advanced metering and meter information networks to residential customers and nonresidential customers other than those required by the independent system operator to have an interval data recorder meter. The commission shall ensure that the nonbypassable surcharge reflects a deployment of advanced meters that is no more than one-third of the utility's total meters over each calendar year and shall ensure that the nonbypassable surcharge does not result in the utility recovering more than its actual, fully allocated meter and meter information network costs. The expenses must be allocated to the customer classes receiving the services, based on the electric utility's most recently approved tariffs.

(i) Subject to the restrictions in Subsection (h), it is the intent of the legislature that net metering and advanced meter information networks be deployed as rapidly as possible to allow customers to better manage energy use and control costs, and to facilitate demand response initiatives.

(j) Notwithstanding Subsection (b), a nonresidential customer may have a meter installed and metering services provided on a competitive basis as part of an energy savings performance contract.

(k) The commission by rule shall prohibit an electric utility or transmission and distribution utility from selling, sharing, or disclosing 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. The commission shall allow an electric utility or transmission and distribution utility to share information with an affiliated corporation, or other third-party entity, if the information is to be used only for the purpose of providing electric utility service to the customer or other customer-approved services.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2005, 79th Leg., Ch. 1095 (H.B. 2129), Sec. 7, eff. September 1, 2005.

Acts 2007, 80th Leg., R.S., Ch. 527 (S.B. 831), Sec. 10, eff. June 16, 2007.

Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 20, eff. September 1, 2007.

Acts 2009, 81st Leg., R.S., Ch. 87 (S.B. 1969), Sec. 27.001(110), eff. September 1, 2009.

Acts 2013, 83rd Leg., R.S., Ch. 170 (H.B. 1600), Sec. 1.07, eff. September 1, 2013.

Sec. 39.108. CONTRACTUAL OBLIGATIONS. This chapter may not:

(1) interfere with or abrogate the rights or obligations of any party, including a retail or wholesale customer, to a contract with an investor-owned electric utility, river authority, municipally owned utility, or electric cooperative;

(2) interfere with or abrogate the rights or obligations of a party under a contract or agreement concerning certificated utility service areas; or

(3) result in a change in wholesale power costs to wholesale customers in Texas purchasing electricity under wholesale power contracts the pricing provisions of which are based on formulary rates, fuel adjustments, or average system costs.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.109. NEW OWNER OR SUCCESSOR. (a) To ensure the continued safe and reliable operation of electric generating facilities, the commission shall require a generating facility that is transferred to a new owner or successor in interest between June 1, 1999, and January 1, 2002, to continue to be operated and maintained by the same operating personnel for not less than two years, except that the personnel may be dismissed for cause.

(b) This section shall apply only if the facility is actually operated during the two-year period after the sale.

(c) This section shall not require that the purchaser cause the facility to be operated in whole or in part, nor shall it preclude a temporary closure of the facility during the two-year period.

(d) This section shall not create any obligation extending after the two-year period following the sale.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.110. WHOLESALE INDEXED PRODUCTS PROHIBITED. (a) In this section, "wholesale indexed product" means a retail electric product in which the price a customer pays for electricity includes a direct pass-through of real-time settlement point prices determined by the independent organization certified under Section 39.151 for the ERCOT power region.

(b) An aggregator, a broker, or a retail electric provider may not offer a wholesale indexed product to a residential or small commercial customer.

(c) An aggregator, a broker, or a retail electric provider may enroll a customer other than a residential and small commercial customer in a wholesale indexed product only if the provider, aggregator, or broker obtains before the customer's enrollment an acknowledgment signed by the customer that the customer accepts the potential price risks associated with a wholesale indexed product.

(d) An acknowledgment required by Subsection (c) must include the following statement, in clear, boldfaced text:

> "I understand that the volatility and fluctuation of wholesale energy pricing may cause my energy bill to be multiple times higher in a month in which wholesale energy prices are high. I understand that I will be responsible for charges caused by fluctuations in wholesale energy prices."

(e) An acknowledgment required by Subsection (c) may be included as an addendum to a contract.

(f) A retail electric provider that provides a wholesale indexed product to a customer must keep on file the acknowledgment required by Subsection (c) for each customer while the customer is enrolled with the retail electric provider in the wholesale indexed product.

Added by Acts 2021, 87th Leg., R.S., Ch. 132 (H.B. 16), Sec. 1, eff. September 1, 2021.

Sec. 39.112. NOTICE OF EXPIRATION AND PRICE CHANGE. (a) In this section, "fixed rate product" means a retail electric product with a term of at least three months for which the price for each billing period, including recurring charges, does not change throughout the term of the contract, except that the price may vary to reflect actual changes in transmission and distribution utility charges, changes to ERCOT or Texas Regional Entity administrative fees charged to loads, or changes to federal, state, or local laws that result in new or modified fees or costs that are not within the retail electric provider's control.

(b) A retail electric provider shall provide a residential customer who has a fixed rate product with at least three written notices of the date the fixed rate product will expire. The notices must be provided during the last third of the contract period and in intervals that allow for, as practicable, even distribution of the notices throughout the last third of the contract period. The final notice for a contract with a period of more than four months must be provided at least 30 days before the date that the contract will expire. The final notice for a contract with a period of less than four months must be provided at least 15 days before the date that the contract will expire.

(c) The retail electric provider must provide each notice required by Subsection (b) to the customer by mail at the customer's billing address, unless the customer has opted to receive communications electronically from the retail electric provider.

(d) If the retail electric provider has access to customer contact information that allows the provider to send the customer a text message or call the customer, and the customer has agreed to receive notices by text message or call, the retail electric provider may provide additional notice to the customer by text message or call of the date the fixed rate product will expire. Notice provided by text message or call does not constitute notice under Subsection (b).

(e) A notice required by Subsection (b) must:

(1) for a notice provided by mail, include in a manner visible from the outside of the envelope in which the notice is sent, a statement that reads: "Contract Expiration Notice. See Enclosed.";

(2) if included with a customer's bill, be printed on a separate page or included as a separate document;

(3) include a description of any fees or charges associated with the early termination of the customer's fixed rate product; and

(4) describe any renewal offers the retail electric provider chooses to make available to the customer and identify methods by which the customer may obtain the contract documents for each of the offered products.

(f) The final notice provided under Subsection (b) must include the pricing terms for the default renewal product required by Subsection (h).

(g) A retail electric provider shall include on each billing statement, in boldfaced and underlined text, the end date of the fixed rate product.

(h) Except as provided by Subsection (j), if a customer does not select another retail electric product before the expiration of the customer's contract term with a retail electric provider, the provider shall automatically serve the customer through a default renewal product that the customer may cancel at any time without a fee. The default renewal product must be:

(1) a month-to-month product in which the price the customer pays for electricity may vary between billing cycles; and

(2) based on clear terms designed to be easily understood by the average customer.

(i) A retail electric provider shall include in each contract for service the terms of the default renewal product that the customer will automatically be enrolled in under Subsection (h) if the customer does not select another retail electric product before the expiration of the contract term.

(j) If a retail electric provider does not provide notice of the expiration of a customer's contract with the provider in accordance with this section and the customer does not select another retail electric product before the expiration of the customer's contract term with the provider, the retail electric provider must continue to serve the customer under the pricing terms of the fixed rate product contract until:

(1) the provider provides notice of the expiration of the contract in accordance with this section; or

(2) the customer selects another retail electric product.

(k) No provision in this section shall be construed to prohibit the commission from adopting rules that would provide a greater degree of customer protection.

Added by Acts 2009, 81st Leg., R.S., Ch. 648 (H.B. 1822), Sec. 5, eff. September 1, 2009.

Amended by:

Acts 2021, 87th Leg., R.S., Ch. 132 (H.B. 16), Sec. 2, eff. September 1, 2021.

SUBCHAPTER D. MARKET STRUCTURE

Sec. 39.151. ESSENTIAL ORGANIZATIONS. (a) A power region must establish one or more independent organizations to perform the following functions:

(1) ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms;

(2) ensure the reliability and adequacy of the regional electrical network;

(3) 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

(4) ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region.

(b) "Independent organization" means 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.

(c) The commission shall certify an independent organization or organizations to perform the functions prescribed by this section. The commission shall apply the provisions of this section and Sections 39.1511, 39.1512, and 39.1515 so as to avoid conflict with a ruling of a federal regulatory body.

(d) The commission shall adopt and enforce rules relating to the reliability of the regional electrical network and accounting for the production and delivery of electricity among generators and all other market participants, or may delegate those responsibilities to an independent organization. An independent organization certified by the commission is directly responsible and accountable to the commission. The commission has complete authority to oversee and investigate the independent organization's finances, budget, and operations as necessary to ensure the organization's accountability and to ensure that the organization adequately performs the organization's functions and duties. The independent organization shall fully cooperate with the commission in the commission's oversight and investigatory functions. The commission may take appropriate action against an independent organization that does not adequately perform the organization's functions or duties or does not comply with this section, including decertifying the organization or assessing an administrative penalty against the organization. The commission by rule shall adopt procedures governing decertification of an independent organization, selecting and certifying a successor organization, and transferring assets to the successor organization to ensure continuity of operations in the region. The commission may not implement, by order or by rule, a requirement that is contrary to an applicable federal law or rule.

(d-1) The commission shall require an independent organization certified by the commission under this section to submit to the commission the organization's entire proposed annual budget. The commission shall review the proposed budgets either annually or biennially and may approve, disapprove, or modify any item included in a proposed budget. The commission by rule shall establish the type of information or documents needed to effectively evaluate the proposed budget and reasonable dates for the submission of that information or those documents. The commission shall establish a procedure to provide public notice of and public participation in the budget review process.

(d-2) Except as otherwise agreed to by the commission and an independent organization certified by the commission under this section, the organization must submit to the commission for review and approval proposals for obtaining debt financing or for refinancing existing debt. The commission may approve, disapprove, or modify a proposal.

(d-3) An independent organization certified by the commission under this section shall develop proposed performance measures to track the organization's operations. The independent organization must submit the proposed performance measures to the commission for review and approval. The commission shall review the organization's performance as part of the budget review process under Subsection (d-1). The commission shall prepare a report at the time the commission approves the organization's budget detailing the organization's performance and 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.

(d-4) The commission may:

(1) require an independent organization to provide reports and information relating to the independent organization's performance of the functions prescribed by this section and relating to the organization's revenues, expenses, and other financial matters;

(2) prescribe a system of accounts for an independent organization;

(3) conduct audits of an independent organization's performance of the functions prescribed by this section or relating to its revenues, expenses, and other financial matters and may require an independent organization to conduct such an audit;

(4) inspect an independent organization's facilities,

records, and accounts during reasonable hours and after reasonable notice to the independent organization;

(5) assess administrative penalties against an independent organization that violates this title or a rule or order adopted by the commission and, at the request of the commission, the attorney general may apply for a court order to require an independent organization to comply with commission rules and orders in the manner provided by Chapter 15; and

(6) resolve disputes between an affected person and an independent organization and adopt procedures for the efficient resolution of such disputes.

(e) After approving the budget of an independent organization under Subsection (d-1), the commission shall authorize the organization to charge to wholesale buyers and sellers a system administration fee, within a range determined by the commission, that is reasonable and competitively neutral to fund the independent organization's approved budget. The commission shall investigate the organization's cost efficiencies, salaries and benefits, and use of debt financing and may require the organization to provide any information needed to effectively evaluate the reasonableness and neutrality of the fee or to evaluate the effectiveness or efficiency of the organization. The commission shall work with the organization to establish the detail of information, both current and historical, and the time frames the commission needs to effectively evaluate the fee. The commission shall require the organization to closely match actual revenues generated by the 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 surplus or insufficient funds. The commission shall require the organization to submit to the commission, on a schedule determined by the commission, reports that compare actual expenditures with budgeted expenditures.

(e-1) The review and approval of a proposed budget under Subsection (d-1) or a proceeding to authorize and set the range for the amount of a fee under Subsection (e) is not a contested case for purposes of Chapter 2001, Government Code.

(f) In implementing this section, the commission may cooperate with the utility regulatory commission of another state or the federal government and may hold a joint hearing or make a joint investigation with that commission.

(g) To maintain certification as an independent organization for the ERCOT power region under this section, an organization's governing body must be composed of persons selected by the ERCOT board selection committee.

(g-1) The bylaws of an independent organization certified for the ERCOT power region must be approved by and reflect the input of the commission. The bylaws must require that every member of the governing body be a resident of this state and must prohibit a legislator from serving as a member. The governing body must be composed of:

(1) two members of the commission as ex officio nonvoting members:

(A) one of whom must be the presiding officer of the commission; and

(B) one of whom must be designated by the presiding officer of the commission to serve a one-year term on the governing body;

(2) the counsellor as an ex officio voting member representing residential and small commercial consumer interests;

(3) the chief executive officer of the independent organization as an ex officio nonvoting member; and

(4) eight members selected by the selection committee under Section 39.1513 with executive-level experience in any of the following professions:

(A) finance;

(B) business;

(C) engineering, including electrical engineering;

(D) trading;

(E) risk management;

(F) law; or

(G) electric market design.

(g-2) Members of the governing body are entitled to receive a salary for their service.

(g-3) A person does not qualify for selection as a member of the governing body of an independent organization for the ERCOT power region if the person has a fiduciary duty or assets in the electricity market for that region.

(g-4) To maintain certification as an independent organization under this section, the organization's governing body may not include more than two members who are employed by an institution of higher education, as defined by Section 61.003, Education Code, in a professorial role.

(g-5) A former member of the governing body of an independent organization certified under this section may not, before the second anniversary of the date the member ceases to be a member of the governing body, engage in an activity that requires registration under Chapter 305, Government Code.

(g-6) In this subsection, a reference to a protocol includes a rule. Protocols adopted by an independent organization and enforcement actions taken by the organization under delegated authority from the commission are subject to commission oversight and review and may not take effect before receiving commission approval. To maintain certification as an independent organization under this section, the organization's governing body must establish and implement a formal process for adopting new protocols or revisions to existing protocols. The process must require that new or revised protocols may not take effect until the commission approves a market impact statement describing the new or revised protocols. The commission may approve, reject, or remand with suggested modifications to the independent organization's governing body protocols adopted by the organization.

Text of subsection as added by Acts 2023, 88th Leg., R.S., Ch. 464 (S.B. 2013), Sec. 4

(g-7) To maintain certification as an independent organization under this section, the organization must:

(1) identify all employee positions in the

organization that are critical to the security of the electric grid; and

(2) before hiring a person for a position described by Subdivision (1), obtain from the Department of Public Safety or a private vendor criminal history record information relating to the prospective employee and any other background information considered necessary by the independent organization or required by the commission.

Text of subsection as added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 15

(g-7) The presiding officer of the commission shall designate commissioners to serve terms on the independent organization's governing body under Subsection (g-1)(1)(B) in the order in which the commissioners were first appointed to the commission. A commissioner may not serve an additional term until each commissioner has served a term.

(h) The ERCOT independent system operator may meet the criteria relating to the other functions of an independent organization provided by Subsection (a) by adopting procedures and acquiring resources needed to carry out those functions, consistent with any rules or orders of the commission.

(i) The commission may delegate authority to the existing independent system operator in ERCOT to enforce operating standards within the ERCOT regional electrical network and to establish and oversee transaction settlement procedures. The commission may establish the terms and conditions for the ERCOT independent system operator's authority to oversee utility dispatch functions after the introduction of customer choice.

(j) A retail electric provider, municipally owned utility, electric cooperative, power marketer, transmission and distribution utility, or power generation company shall observe all scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, and procedures established by the independent system operator in ERCOT. Failure to comply with this subsection may result in the revocation, suspension, or amendment of a certificate as provided by Section 39.356 or in the imposition of an administrative penalty as provided by Section 39.357.

(j-1) Notwithstanding Subsection (j) of this section, Section 39.653(c), or any other law, the independent system operator in the ERCOT power region may not reduce payments to or uplift short-paid amounts to a municipally owned utility that becomes subject to the jurisdiction of that independent system operator on or after May 29, 2021, and before December 30, 2021, related to a default on a payment obligation by a market participant that occurred before May 29, 2021.

(k) To the extent the commission has authority over an independent organization outside of ERCOT, the commission may delegate authority to the independent organization consistent with Subsection (i).

(l) No operational criteria, protocols, or other requirement established by an independent organization, including the ERCOT independent system operator, may adversely affect or impede any manufacturing or other internal process operation associated with an industrial generation facility, except to the minimum extent necessary to assure reliability of the transmission network.

(m) A power region outside of ERCOT shall be deemed to have met the requirement to establish an independent organization to perform the transmission functions specified in Subsection (a) if the Federal Energy Regulatory Commission has approved a regional transmission organization for the region and found that the regional transmission organization meets the requirements of Subsection (a).

(n) An independent organization certified by the commission under this section is subject to review under Chapter 325, Government Code (Texas Sunset Act), but is not abolished under that chapter. The independent organization shall be reviewed during the periods in which the Public Utility Commission of Texas is reviewed.

(o) An independent organization certified by the commission under this section shall:

(1) conduct internal cybersecurity risk assessment,

vulnerability testing, and employee training to the extent the independent organization is not otherwise required to do so under applicable state and federal cybersecurity and information security laws; and

(2) submit a report annually to the commission on the independent organization's compliance with applicable cybersecurity and information security laws.

(p) Information submitted in a report under Subsection (o) is confidential and not subject to disclosure under Chapter 552, Government Code.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2005, 79th Leg., Ch. 797 (S.B. 408), Sec. 9, eff. September 1, 2005.

Acts 2011, 82nd Leg., R.S., Ch. 1232 (S.B. 652), Sec. 1.09(a), eff. June 17, 2011.

Acts 2013, 83rd Leg., R.S., Ch. 170 (H.B. 1600), Sec. 1.08, eff. September 1, 2013.

Acts 2019, 86th Leg., R.S., Ch. 509 (S.B. 64), Sec. 23, eff. September 1, 2019.

Acts 2021, 87th Leg., R.S., Ch. 425 (S.B. 2), Sec. 3, eff. June 8, 2021.

Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 3, eff. June 16, 2021.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 15, eff. September 1, 2023.

Acts 2023, 88th Leg., R.S., Ch. 464 (S.B. 2013), Sec. 4, eff. June 9, 2023.

Sec. 39.1511. PUBLIC MEETINGS OF THE GOVERNING BODY OF AN INDEPENDENT ORGANIZATION. (a) Meetings of the governing body of an independent organization certified under Section 39.151 and meetings of a subcommittee that includes a member of the governing body must be open to the public. The bylaws of the independent organization and the rules of the commission may provide for the governing body or subcommittee to enter into executive session closed to the public only to address risk management or a matter that the independent organization would be authorized to consider in a closed meeting if the independent organization were governed under Chapter 551, Government Code.

(a-1) An independent organization's governing body or a subcommittee may adopt a policy allowing the governing body or subcommittee to enter into an executive session closed to the public and commissioners, including the commissioners serving as ex officio nonvoting members, only to address a contested case, as defined by Section 2001.003, Government Code, or a personnel matter that is unrelated to members of the governing body.

(b) The bylaws of the independent organization and rules of the commission must ensure that a person interested in the activities of the independent organization has an opportunity to obtain at least seven days' advance notice of meetings and the planned agendas of the meetings and an opportunity to comment on matters under discussion at the meetings. The bylaws and commission rules governing meetings of the governing body may provide for a shorter period of advance notice and for meetings by teleconference technology for governing body meetings to take action on urgent matters. The bylaws and rules must require actions taken on short notice or at teleconference meetings to be ratified at the governing body's next regular meeting. The notice requirements may be met by a timely electronic posting on the Internet.

(c) The commission shall ensure that an independent organization certified under Section 39.151 makes publicly accessible without charge live Internet video of all public meetings subject to this section for viewing from an Internet website.

Added by Acts 2005, 79th Leg., Ch. 797 (S.B. 408), Sec. 10, eff. September 1, 2005.

Amended by:

Acts 2009, 81st Leg., R.S., Ch. 400 (H.B. 1783), Sec. 2, eff. September 1, 2009.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 16, eff. September 1, 2023.

Sec. 39.1512. DISCLOSURE OF INTEREST IN MATTER BEFORE INDEPENDENT ORGANIZATION'S GOVERNING BODY; PARTICIPATION IN DECISION. (a) If a matter comes before the governing body of an independent organization certified under Section 39.151 and a member has a direct interest in that matter or is employed by or has a substantial financial interest in a person who has a direct interest in that matter, that member shall publicly disclose the fact of that interest to the governing body at a public meeting of the body. The member shall recuse himself or herself from the governing body's deliberations and actions on the matter and may not vote on the matter or otherwise participate in a governing body decision on the matter.

(b) A disclosure made under Subsection (a) shall be entered in the minutes of the meeting at which the disclosure is made.

(c) The fact that a member is recused from a vote or decision by application of this section does not affect the existence of a quorum.

Added by Acts 2005, 79th Leg., Ch. 797 (S.B. 408), Sec. 10, eff. September 1, 2005.

Sec. 39.1513. ERCOT BOARD SELECTION COMMITTEE. (a) The ERCOT board selection committee is composed of:

(1) one member appointed by the governor;

(2) one member appointed by the lieutenant governor; and

(3) one member appointed by the speaker of the house of representatives.

(b) A person may not be appointed as a member of the committee unless the person is a resident of this state.

(c) A member of the committee is not entitled to compensation for serving as a member but is entitled to reimbursement for actual and necessary expenses incurred in performing the official duties of office.

(d) The committee shall select members eligible under Section 39.151 to serve on the governing body of an independent organization certified under that section for the ERCOT power region and shall designate the chair and vice chair of the governing body from those members.

(e) The ERCOT board selection committee shall retain an outside consulting firm to help select members of the governing body under Subsection (d).

Added by Acts 2021, 87th Leg., R.S., Ch. 425 (S.B. 2), Sec. 4, eff. June 8, 2021.

Sec. 39.1514. COMMISSION DIRECTIVES TO INDEPENDENT ORGANIZATION. (a) The commission may not use a verbal directive to direct an independent organization certified under Section 39.151 to take an official action. The commission may direct the organization to take an official action only through:

(1) a contested case;

(2) rulemaking; or

(3) a memorandum or written order adopted by a majority vote.

(a-1) The commission must use a contested case or rulemaking process to direct an independent organization certified under Section 39.151 to take an official action that will create a new cost or fee, increase an existing cost or fee, or impose significant operational obligations on an entity.

(b) The commission by rule shall:

(1) specify the types of directives the commission may issue through a contested case, rulemaking, memorandum, or written order, in accordance with Subsection (a-1);

(2) require that proposed commission directives be included as an item on a commission meeting agenda and require the commission to allow members of the public an opportunity to comment on the agenda item; and

(3) establish a reasonable timeline for the release before a commission meeting of discussion materials relevant to any proposed commission directives included as agenda items for that meeting.

(c) Notwithstanding another provision of this section, the commission may use a verbal directive to direct an independent organization to take an official action in an urgent or emergency situation that poses an imminent threat to public health, public safety, or the reliability of the power grid. If the commission uses a verbal directive, the commission shall provide written documentation of the directive to the independent organization not later than 72 hours after the urgent or emergency situation ends. The commission by rule shall establish criteria for determining whether a situation is urgent or an emergency under this subsection and establish a process by which the commission will issue directives to the independent organization under this subsection.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 17, eff. September 1, 2023.

Sec. 39.1515. WHOLESALE ELECTRIC MARKET MONITOR. (a) An independent organization certified under Section 39.151 shall contract with an entity selected by the commission to act as the commission's wholesale electric market monitor to detect and prevent market manipulation strategies, recommend measures to enhance the efficiency of the wholesale market, and provide independent analysis of any material changes proposed to the wholesale market. The commission may not restrict the market monitor from appearing or speaking before or providing analysis to the legislature. The independent organization may not substantially modify the market monitor's contract unless the modification is approved by a majority of the commissioners.

(b) The independent organization shall provide to the personnel of the market monitor:

(1) full access to the organization's main operations center and the organization's records that concern operations, settlement, and reliability; and

(2) other support and cooperation the commission determines is necessary for the market monitor to perform the market monitor's functions.

(c) The independent organization shall use money from the fee authorized by Section 39.151(e) to pay for the market monitor's activities.

(d) The commission is responsible for ensuring that the market monitor has the resources, expertise, and authority necessary to monitor the wholesale electric market effectively and shall adopt rules and perform oversight of the market monitor as necessary. The market monitor shall operate under the supervision and oversight of the commission. The commission shall retain all enforcement authority conferred under this title, and this section may not be construed to confer enforcement authority on the market monitor or to authorize the commission to delegate the commission's enforcement authority to the market monitor. The commission by rule shall define:

(1) the market monitor's monitoring responsibilities, including reporting obligations and limitations;

(2) the standards for funding the market monitor, including staffing requirements;

(3) qualifications for personnel of the market monitor; and

(4) ethical standards for the market monitor and the personnel of the market monitor.

(e) In adopting rules governing the standards for funding the market monitor, the commission shall consult with a subcommittee of the independent organization's governing body to receive information on how money is or should be spent for monitoring functions. Rules governing ethical standards must include provisions designed to ensure that the personnel of the market monitor are professionally and financially independent from market participants. The commission shall develop and implement policies that clearly separate the policymaking responsibilities of the commission and the monitoring, analysis, and reporting responsibilities of the market monitor.

(f) The market monitor immediately shall report in writing directly to the commission and commission staff all potential market manipulations and all discovered or potential violations of commission rules or rules of the independent organization.

(g) The personnel of the market monitor may communicate with commission staff on any matter without restriction.

(h) The market monitor annually shall submit to the commission and the independent organization a report that identifies market design flaws and recommends methods to correct the flaws. The commission and the independent organization shall review the report and evaluate whether changes to rules of the commission or the independent organization should be made.

(i) Not later than December 1 of each year, the commission shall submit a report to the legislature that describes for the 12-month period preceding the report's submission:

(1) the number of instances in which the market monitor reported potential market manipulation to the commission or commission staff;

(2) the statutes, commission rules, and rules of the independent organization alleged to have been violated by the reported entities; and

(3) the number of instances reported under Subdivision (1) for which the commission instituted a formal investigation on its own motion or commission staff initiated an enforcement action.

Added by Acts 2005, 79th Leg., Ch. 797 (S.B. 408), Sec. 10, eff. September 1, 2005.

Amended by:

Acts 2013, 83rd Leg., R.S., Ch. 170 (H.B. 1600), Sec. 1.09, eff. September 1, 2013.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 18, eff. September 1, 2023.

Sec. 39.1516. CYBERSECURITY MONITOR. (a) In this section, "monitored utility" means:

(1) a transmission and distribution utility;

(2) a corporation described in Section 32.053;

(3) a municipally owned utility or electric cooperative that owns or operates equipment or facilities in the ERCOT power region to transmit electricity at 60 or more kilovolts; or

(4) an electric utility, municipally owned utility, or electric cooperative that operates solely outside the ERCOT power region that has elected to participate under Subsection (d).

(b) The commission and the independent organization certified under Section 39.151 shall contract with an entity selected by the commission to act as the commission's cybersecurity monitor to:

(1) manage a comprehensive cybersecurity outreach program for monitored utilities;

(2) meet regularly with monitored utilities to discuss emerging threats, best business practices, and training opportunities;

(3) review self-assessments voluntarily disclosed by monitored utilities of cybersecurity efforts;

(4) research and develop best business practices regarding cybersecurity; and

(5) report to the commission on monitored utility cybersecurity preparedness.

(c) The independent organization certified under Section 39.151 shall provide to the cybersecurity monitor any access, information, support, and cooperation that the commission determines is necessary for the monitor to perform the functions described by Subsection (b). The independent organization shall use funds from the fee authorized by Section 39.151(e) to pay for the cybersecurity monitor's activities.

(d) An electric utility, municipally owned utility, or electric cooperative that operates solely outside the ERCOT power region may elect to participate in the cybersecurity monitor program or to discontinue participation. The commission shall adopt rules establishing:

(1) procedures for an electric utility, municipally owned utility, or electric cooperative to notify the commission, the independent organization certified under Section 39.151, and the cybersecurity monitor that the utility or cooperative elects to participate or to discontinue participation; and

(2) a mechanism to require an electric utility, municipally owned utility, or electric cooperative that elects to participate to contribute to the costs incurred by the independent organization under this section.

(e) The cybersecurity monitor shall operate under the supervision and oversight of the commission.

(f) The commission shall adopt rules as necessary to implement this section and may enforce the provisions of this section in the manner provided by this title. This section does not grant enforcement authority to the cybersecurity monitor or authorize the commission to delegate the commission's enforcement authority to the cybersecurity monitor. This section does not grant enforcement authority to the commission beyond authority explicitly provided for in this title.

(g) The staff of the cybersecurity monitor may communicate with commission staff about any cybersecurity information without restriction. Commission staff shall maintain the confidentiality of the cybersecurity information. Notwithstanding any other law, commission staff may not disclose information obtained under this section in an open meeting or through a response to a public information request.

(h) Information written, produced, collected, assembled, or maintained under Subsection (b), (c), or (g) is confidential and not subject to disclosure under Chapter 552, Government Code. A governmental body is not required to conduct an open meeting under Chapter 551, Government Code, to deliberate a matter described by Subsection (b), (c), or (g).

Added by Acts 2019, 86th Leg., R.S., Ch. 610 (S.B. 936), Sec. 3, eff. September 1, 2019.

Sec. 39.152. QUALIFYING POWER REGIONS. (a) The commission shall certify a power region if:

(1) a sufficient number of interconnected utilities in the power region fall under the operational control of an independent organization as described by Section 39.151;

(2) the power region has a generally applicable tariff that guarantees open and nondiscriminatory access for all users to transmission and distribution facilities in the power region as provided by Section 39.203; and

(3) no person owns and controls more than 20 percent of the installed generation capacity located in or capable of delivering electricity to a power region, as determined according to Section 39.154.

(b) In determining whether a power region not entirely within the state meets the requirements of this section, the commission shall consider the extent to which the available transmission facilities limit the delivery of electricity from generators located outside the state to areas of the power region within the state.

(c) For a power region outside of ERCOT, the requirements of Subsection (a)(2) shall be deemed to have been met if power aggregating to approximately 50,000 megawatts can be delivered to the portion of the power region that is in this state through the payment of not more than one transmission tariff.

(d) For a power region outside of ERCOT, a power generation company that is affiliated with an electric utility may elect to demonstrate that it meets the requirements of Subsection (a)(3) by showing that it does not own and control more than 20 percent of the installed capacity in a geographic market that includes the power region, using the guidelines, standards, and methods adopted by the Federal Energy Regulatory Commission.

(e) In a power region outside of ERCOT, if customer choice is introduced before the requirements of Subsection (a) are met, an affiliated retail electric provider may not compete for retail customers in any area of the power region that is within this state and outside of the affiliated transmission and distribution utility's certificated service area unless the affiliated power generation company makes a commitment to maintain and does maintain rates that are based on cost of service for any electric cooperative or municipally owned utility that was a wholesale customer on January 1, 1999, and was purchasing power at rates that were based on cost of service. This subsection requires a power generation company to sell power at rates that are based on cost of service, notwithstanding the expiration of a contract for that service, until the requirements of Subsection (a) are met.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.153. CAPACITY AUCTION. (a) Each electric utility subject to this section shall sell at auction, at least 60 days before the date set for customer choice to begin, entitlements to at least 15 percent of the electric utility's Texas jurisdictional installed generation capacity. For the purposes of this section, the term "electric utility" includes any affiliated power generation company that is unbundled from the electric utility in accordance with Section 39.051, but does not include any entity owning less than 400 megawatts of installed generation capacity.

(b) The obligation to auction the entitlements shall continue until the earlier of 60 months after the date customer choice is introduced or the date the commission determines that 40 percent 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.

(c) An affiliate of the electric utility selling entitlements in the auction required by this section may not purchase entitlements from the affiliated electric utility at the auction. Entitlements may only be purchased by entities lawfully able to sell electricity in Texas.

(d) An electric utility may choose to auction additional entitlements beyond those required by Subsection (a) or continue to auction entitlements after the period required by Subsection (b) in order to comply with Section 39.154.

(e) The commission shall adopt rules by December 31, 2000, that define the scope of the capacity entitlements to be auctioned. Entitlements may be auctioned in blocks of less than 15 percent. The rules shall state the minimum amount of capacity that can be sold at auction as an entitlement. At a minimum, the rules shall provide that the entitlements:

(1) may be sold and purchased in periods of not less than one month nor more than four years;

(2) may be resold to any lawful purchaser, except for a retail electric provider affiliated with the electric utility that originally auctioned the entitlement;

(3) include no possessory interest in the unit from which the power is produced;

(4) include no obligations of a possessory owner of an interest in the unit from which the power is produced; and

(5) give the purchaser the right to designate the

dispatch of the entitlement, subject to planned outages, outages beyond the control of the utility operating the unit, and other considerations subject to the oversight of the applicable independent organization.

(f) The commission shall adopt rules by December 31, 2000, that prescribe the procedure for the auction of the entitlements. The rules shall include:

(1) a process for conducting the auction or auctions, including who shall conduct it, how often it shall be conducted, and how winning bidders shall be determined;

(2) a process for the electric utility to designate which generation units or combination of units are offered for auction;

(3) a provision for the utility to establish an opening bid price based on the electric utility's expected cost, with the commission prescribing the means for determining the opening bid price, which may not include return on equity; and

(4) a provision that allows a bidder to specify the magnitude and term of the entitlement, subject to the conditions established in Subsection (e).

(g) In adopting the process under Subsection (f)(2), the commission shall consider the furtherance of the development of the competitive market, the cost of transmission, physical constraints of the transmission system, the proximity of the generation to load, economic efficiency, and any other factors the commission finds relevant. The process may provide for commission approval of the designation before auction. The commission may consult with the applicable independent organization to develop the process.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.154. LIMITATION OF OWNERSHIP OF INSTALLED CAPACITY. (a) Beginning on the date of introduction of customer choice, a power generation company may not own and control more than 20 percent of the installed generation capacity located in, or capable of delivering electricity to, a power region.

(b) In a power region not entirely within the state, the commission may waive or modify the requirement in Subsection (a) on a finding of good cause.

(c) In determining the percentage shares of installed generation capacity under this section, 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 Sections 39.153(a) and (d).

(d) In this chapter, "installed generation capacity" means all potentially marketable electric generation capacity, including the capacity of:

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

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

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

(e) In determining the percentage shares of installed generation capacity owned and controlled by a power generation company under this section and Section 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 Section 39.264. This subsection applies only to a power generation company that is affiliated with an electric utility that owned and controlled more than 27 percent of the installed generation capacity in the power region on January 1, 1999.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.155. COMMISSION ASSESSMENT OF MARKET POWER. (a) Each person, municipally owned utility, electric cooperative, and river authority that owns generation facilities and offers electricity for sale in this state shall report to the commission its installed generation capacity, the total amount of capacity available for sale to others, the total amount of capacity under contract to others, the total amount of capacity dedicated to its own use, its annual wholesale power sales in the state, its annual retail power sales in the state, and any other information necessary for the commission to assess market power or the development of a competitive retail market in the state. The commission shall by rule prescribe the nature and detail of the reporting requirements and shall administer those reporting requirements in a manner that ensures the confidentiality of competitively sensitive information.

(b) Repealed by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 46(a)(3), eff. September 1, 2023.

(c) Before the date of introduction of customer choice in a power region other than ERCOT, each electric utility owning transmission and distribution facilities in that region shall submit an annual report to the commission identifying existing and potential transmission and distribution constraints and system needs in the power region, alternatives for meeting system needs, and recommendations for meeting system needs as directed by the commission.

(d) In a qualifying power region, the report required by Subsection (c) shall be submitted by the independent organization or organizations having authority over the power region or discrete areas thereof.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 19, eff. September 1, 2023.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 46(a)(3), eff. September 1, 2023.

Sec. 39.156. MARKET POWER MITIGATION PLAN. (a) In this section, "market power mitigation plan" or "plan" means 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 Section 39.154.

(b) An electric utility or power generation company owning and controlling more than 20 percent of the 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.

(c) The 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 Section 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) For the purposes of this section, generation capacity shall be net of the generation capacity subject to an auction under Section 39.153.

(e) The plan shall be in a form prescribed by the commission and shall provide information the commission finds reasonably necessary to evaluate the plan.

(f) The commission shall approve, modify, or reject a plan within 180 days after the date of a filing under Subsection (b). The commission may not modify a plan to require divestiture by the electric utility or the power generation company.

(g) In reaching its determination under Subsection (f), 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; and

(5) whether the plan is consistent with the public interest.

(h) 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 shall modify or repeal an electric utility's or power generation company's mitigation plan.

(i) If an electric utility's or a 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 Section 39.153, subject to commission approval, of any capacity exceeding the maximum allowable capacity prescribed by Section 39.154 until the time a mitigation plan is approved.

(j) An auction under Subsection (i) shall be held not later than 60 days after the date the order is entered.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.157. COMMISSION AUTHORITY TO ADDRESS MARKET POWER. (a) The commission shall monitor market power associated with the generation, transmission, distribution, and sale of electricity in this state. On a finding that market power abuses or other violations of this section are occurring, the commission shall require reasonable mitigation of the market power by ordering the construction of additional transmission or distribution facilities, by seeking an injunction or civil penalties as necessary to eliminate or to remedy the market power abuse or violation as authorized by Chapter 15, by imposing an administrative penalty as authorized by Chapter 15, by ordering the disgorgement of excess revenue as authorized by Chapter 15, or by suspending, revoking, or amending a certificate or registration as authorized by Section 39.356. Section 15.024(c) does not apply to an administrative penalty imposed under this section. For purposes of this subchapter, market power abuses are 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. For purposes of this section, "market power abuses" include predatory pricing, withholding of production, precluding entry, and collusion. A violation of the code of conduct provided by Subsection (d) that materially impairs the ability of a person to compete in a competitive market shall be deemed to be an abuse of market power. The possession of a high market share in a market open to competition may not, of itself, be deemed to be an abuse of market power; however, this sentence shall not affect the application of state and federal antitrust laws.

(b) Beginning on the date of introduction of customer choice, a person that owns generation facilities may not own transmission or distribution facilities in this state except for those 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" under Section 31.002. However, nothing in this chapter shall prohibit a power generation company affiliated with a transmission and distribution utility from owning generation facilities.

(c) The commission shall monitor market shares of installed capacity to ensure that the limitations in Section 39.154 are not exceeded. If the commission finds that a person has violated a limitation in Section 39.154, the commission shall order the person to file, within 60 days of the date of the order, a market power mitigation plan consistent with the requirements in Section 39.156.

(d) Not later than January 10, 2000, the commission shall adopt rules and enforcement procedures to govern transactions or activities between a transmission and distribution utility and its competitive affiliates to avoid potential market power abuses and cross-subsidizations between regulated and competitive activities both during the transition to and after the introduction of competition. Nothing in this subsection is intended to affect or modify the obligations 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 or the Securities and Exchange Commission. A utility that is subject to statutes or regulations in other states 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. The rules adopted under this section shall ensure that:

(1) a utility makes any products and services, other than corporate support services, that it provides to a competitive affiliate available, contemporaneously and in the same manner, to the competitive affiliate's competitors and applies its tariffs, prices, terms, conditions, and discounts for those products and services in the same manner to all similarly situated entities;

(2) a utility does not:

(A) give a competitive affiliate or a competitive affiliate's customers any preferential advantage, access, or treatment regarding services other than corporate support services; or

(B) act in a manner that is discriminatory or anticompetitive with respect to a nonaffiliated competitor of a competitive affiliate;

(3) a utility providing electric transmission or distribution services:

(A) provides those services on nondiscriminatory terms and conditions;

(B) does not establish as a condition for the provision of those services the purchase of other goods or services from the utility or the competitive affiliate; and

(C) does not provide competitive affiliates preferential access to the utility's transmission and distribution systems or to information about those systems;

(4) a utility does not release any proprietary customer information to a competitive affiliate or any other entity, other than an independent organization as defined by Section 39.151 or a provider of corporate support services for the purposes of providing the services, without obtaining prior verifiable authorization, as determined from the commission, from the customer;

(5) a utility does not:

(A) communicate with a current or potential customer about products or services offered by a competitive affiliate in a manner that favors a competitive affiliate; or

(B) allow a competitive affiliate, before September 1, 2005, to use the utility's corporate name, trademark, brand, or logo unless the competitive affiliate includes on employee business cards and in its advertisements of specific services to existing or potential residential or small commercial customers locating within the utility's certificated service area a disclaimer that states, "(Name of competitive affiliate) is not the same company as (name of utility) and is not regulated by the Public Utility Commission of Texas, and you do not have to buy (name of competitive affiliate)'s products to continue to receive quality regulated services from (name of utility).";

(6) a utility does not conduct joint advertising or promotional activities with a competitive affiliate in a manner that favors the competitive affiliate;

(7) a utility is a separate, independent entity from any competitive affiliates and, except as provided by Subdivisions (8) and (9), does not share employees, facilities, information, or other resources, other than permissible corporate support services, with those competitive affiliates unless the utility can prove to the commission that the sharing will not compromise the public interest;

(8) a utility's office space is physically separated from the office space of the utility's competitive affiliates by being located in separate buildings or, if within the same building, by a method such as having the offices on separate floors or with separate access, unless otherwise approved by the commission;

(9) a utility and a competitive affiliate:

(A) may, to the extent the utility implements adequate safeguards precluding employees of a competitive affiliate from gaining access to information in a manner inconsistent with Subsection (g) or (i), share common officers and directors, property, equipment, offices to the extent consistent with Subdivision (8), credit, investment, or financing arrangements to the extent consistent with Subdivision (17), computer systems, information systems, and corporate support services; and

(B) are not required to enter into prior written contracts or competitive solicitations for non-tariffed transactions between the utility and the competitive affiliate, except that the commission by rule may require the utility and the competitive affiliate to enter into prior written contracts or competitive solicitations for certain classes of transactions, other than corporate support services, that have a per unit value of more than $75,000 or that total more than $1 million;

(10) a utility does not temporarily assign, for less than one year, employees engaged in transmission or distribution system operations to a competitive affiliate unless the employee does not have knowledge of information that is intended to be protected under this section;

(11) a utility does not subsidize the business activities of an affiliate with revenues from a regulated service;

(12) a utility and its affiliates fully allocate costs for any shared services, corporate support services, and other items described by Subdivisions (8) and (9);

(13) a utility and its affiliates keep separate books of accounts and records and the commission may review records relating to a transaction between a utility and an affiliate;

(14) assets transferred or services provided between a utility and an affiliate, other than transfers that facilitate unbundling under Section 39.051 or asset valuation under Section 39.262, are priced at a level that is fair and reasonable to the customers of the utility and reflects the market value of the assets or services or the utility's fully allocated cost to provide those assets or services;

(15) regulated services that a utility provides on a routine or recurring basis are included in a tariff that is subject to commission approval;

(16) each transaction between a utility and a competitive affiliate is conducted at arm's length; and

(17) a utility does not allow an affiliate to obtain

credit under an arrangement that would include a specific pledge of assets in the rate base of the utility or a pledge of cash reasonably necessary for utility operations.

(e) The commission shall by rule establish a code of conduct that must be observed by electric cooperatives and municipally owned utilities and their affiliates to protect against anticompetitive practices. The rules adopted by the commission under this subsection shall be consistent with Chapters 40 and 41 and may not be more restrictive than the rules adopted under Subsection (d).

(f) Following review of the annual report submitted to it under Section 39.155(c), the commission shall determine whether specific transmission or distribution constraints or bottlenecks within this state give rise to market power in specific geographic markets in the state. The commission, on a finding that specific transmission or distribution constraints or bottlenecks within this state give rise to market power, may order reasonable mitigation of that potential market power by ordering, under Section 39.203(e), one or more electric utilities or transmission and distribution utilities to construct additional transmission or distribution capacity, or both, subject to the certification provisions of this title.

(g) The sharing of corporate support services in accordance with this section may not allow or provide a means for the transfer of confidential information from a utility to an affiliate, create the opportunity for preferential treatment or an unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross-subsidization of affiliates.

(h) A utility or competitive affiliate may not circumvent the provisions or the intent of the provisions of Subsection (d) by using any utility affiliate to provide information, services, or subsidies between the utility and a competitive affiliate.

(i) In this section:

(1) "Competitive affiliate" means 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.

(2) "Corporate support services" means 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 Subsections (d) and (g), include human resources, procurement, information technology, regulatory services, administrative services, real estate services, legal services, accounting, environmental services, research and development, 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, transmission and distribution system operations, and marketing.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2011, 82nd Leg., R.S., Ch. 996 (H.B. 2133), Sec. 7, eff. September 1, 2011.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 20, eff. September 1, 2023.

Sec. 39.158. MERGERS AND CONSOLIDATIONS. (a) A power generation company that offers electricity for sale in this state in a power region open to customer choice and proposes a transaction to merge, consolidate, or otherwise become affiliated with another power generation company that offers electricity for sale in this state in the same power region shall obtain the approval of the commission before closing if the merged, consolidated, or affiliated entity would own and control more than 10 percent of the total installed generation capacity located in, or capable of delivering electricity to, the power region.

(a-1) An approval required by Subsection (a) must be requested at least 120 days before the date of the proposed closing of the transaction.

(a-2) The commission shall approve a transaction described by Subsection (a) unless the commission finds that the transaction results in a violation of Section 39.154. If the commission finds that the transaction as proposed would violate Section 39.154, the commission may condition approval of the transaction on adoption of reasonable modifications to the transaction as prescribed by the commission to mitigate potential market power abuses.

(a-3) If the commission does not issue an order consistent with Subsection (a-2) before the 121st day after the date the commission receives a request for approval under Subsection (a), the request is considered approved by the commission.

(b) Nothing in this chapter shall be construed to confer immunity from state or federal antitrust laws. This chapter is intended to complement other state and federal antitrust provisions. Therefore, antitrust remedies may also be sought in state or federal court to remedy anticompetitive activities.

(c) This section may not be deemed to authorize commission review or approval of transactions entered into between or among municipally owned utilities, river authorities, special districts created by law, or other political subdivisions, whether or not those transactions may be characterized as mergers, consolidations, or other affiliations, when the transaction is authorized or structured under state law.

(d) Notwithstanding any other provision of this title, an electric utility which, before the effective date of this chapter, entered into a stipulation or agreement in support of approval of a merger which was approved by the commission on or after January 1, 1996, requiring the utility to pass through to ratepayers the savings resulting from the merger of that utility with another utility shall continue to be bound by the terms of that stipulation or agreement. The commission shall ensure that the pass-through of all merger savings required under any such stipulation or agreement shall be fully implemented during the freeze period and shall be reflected in setting the price to beat for that utility.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2019, 86th Leg., R.S., Ch. 433 (S.B. 1211), Sec. 1, eff. September 1, 2019.

Sec. 39.159. POWER REGION RELIABILITY AND DISPATCHABLE GENERATION. (a) For the purposes of this section, a generation facility is considered to be non-dispatchable if the facility's output is controlled primarily by forces outside of human control.

(b) The commission shall ensure that the independent organization certified under Section 39.151 for the ERCOT power region:

(1) establishes requirements to meet the reliability needs of the power region;

(2) periodically, but at least annually, determines the quantity and characteristics of ancillary or reliability services necessary to ensure appropriate reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production in the power region;

(3) procures ancillary or reliability services on a competitive basis to ensure appropriate reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production in the power region;

(4) develops appropriate qualification and performance requirements for providing services under Subdivision (3), including appropriate penalties for failure to provide the services; and

(5) sizes the services procured under Subdivision (3) to prevent prolonged rotating outages due to net load variability in high demand and low supply scenarios.

(c) The commission shall ensure that:

(1) resources that provide services under Subsection (b) are dispatchable and able to meet continuous operating requirements for the season in which the service is procured;

(2) winter resource capability qualifications for a service described by Subsection (b) include on-site fuel storage, dual fuel capability, or fuel supply arrangements to ensure winter performance for several days; and

(3) summer resource capability qualifications for a service described by Subsection (b) include facilities or procedures to ensure operation under drought conditions.

(d) The commission shall require the independent organization certified under Section 39.151 for the ERCOT power region to develop and implement an ancillary services program to procure dispatchable reliability reserve services on a day-ahead and real-time basis to account for market uncertainty. Under the required program, the independent organization shall:

(1) determine the quantity of services necessary based on historical variations in generation availability for each season based on a targeted reliability standard or goal, including intermittency of non-dispatchable generation facilities and forced outage rates, for dispatchable generation facilities;

(2) develop criteria for resource participation that require a resource to:

(A) be capable of running for at least four hours at the resource's high sustained limit;

(B) be online and dispatchable not more than two hours after being called on for deployment; and

(C) have the dispatchable flexibility to address inter-hour operational challenges; and

(3) reduce the amount of reliability unit commitment by the amount of dispatchable reliability reserve services procured under this section.

(e) Notwithstanding Subsection (d)(2)(A), the independent organization certified under Section 39.151 for the ERCOT power region may require a resource to be capable of running for more than four hours as the organization determines is needed.

Added by Acts 2021, 87th Leg., R.S., Ch. 426 (S.B. 3), Sec. 18, eff. June 8, 2021.

Amended by:

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 21, eff. September 1, 2023.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 22, eff. September 1, 2023.

Sec. 39.1591. REPORT ON DISPATCHABLE AND NON-DISPATCHABLE GENERATION FACILITIES. Not later than December 1 of each year, the commission shall file a report with the legislature that:

(1) includes:

(A) the estimated annual costs incurred by load-serving entities under this subchapter associated with backing up dispatchable and non-dispatchable electric generation facilities to guarantee that a firm amount of electric energy will be available to the ERCOT power grid; and

(B) as calculated by the independent system operator, the cumulative annual costs that have been incurred in the ERCOT market to facilitate the transmission of dispatchable and non-dispatchable electricity to load and to interconnect transmission level loads, including a statement of the total cumulative annual costs and of the cumulative annual costs incurred for each type of activity described by this paragraph; and

(2) documents the status of the implementation of this subchapter, including whether the rules and protocols adopted to implement this subchapter have materially improved the reliability, resilience, and transparency of the electricity market.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 23, eff. September 1, 2023.

Sec. 39.1592. GENERATION RELIABILITY REQUIREMENTS. (a) This section applies only to an electric generation facility in the ERCOT power region for which a standard generator interconnection agreement is signed on or after January 1, 2027, that has been in operation for at least one year, and that is not a self-generator.

(b) Not later than December 1 of each year, an owner or operator of an electric generation facility, other than a battery energy storage resource, shall demonstrate to the commission the ability of the owner or operator's portfolio to operate or be available to operate when called on for dispatch at or above the seasonal average generation capability during the times of highest reliability risk, as determined by the commission, due to low operation reserves, as determined by the commission. The owner or operator must be allowed to meet the performance requirements described by this subsection by supplementing or contracting with on-site or off-site resources, including battery energy storage resources. The commission shall determine the average generation capability based on expected resource availability and seasonal-rated capacity on a standalone basis.

(c) The commission shall require the independent organization certified under Section 39.151 for the ERCOT power region to:

(1) enforce the requirements of Subsection (b) by imposing financial penalties, as determined by the commission, for failing to comply with the performance requirements described by that subsection; and

(2) provide financial incentives, as determined by the commission, for exceeding the performance requirements described by that subsection.

(d) The independent organization certified under Section 39.151 for the ERCOT power region may not impose penalties under Subsection (c):

(1) for resource unavailability due to planned maintenance outages or transmission outages;

(2) on resources that are already subject to performance obligations during the highest reliability risk hours under the day-ahead market rules or other ancillary or reliability services established by the commission or the independent organization; or

(3) during hours outside a baseline established by the commission that includes morning and evening ramping periods.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 23, eff. September 1, 2023.

Sec. 39.1593. COST ALLOCATION OF RELIABILITY SERVICES. (a) The commission shall direct the independent organization certified under Section 39.151 for the ERCOT power region to evaluate with input from a technical advisory committee established under the bylaws of the independent organization that includes market participants whether allocating the costs of ancillary and reliability services, including those procured under Section 39.159, as added by Chapter 426 (S.B. 3), Acts of the 87th Legislature, Regular Session, 2021, using a methodology described by Subsection (b) would result in a net savings to consumers in the ERCOT power region compared to allocating all costs of ancillary and reliability services to load to ensure reliability.

(b) The commission shall evaluate whether to allocate the cost of ancillary and reliability services:

(1) on a semiannual basis among electric generation facilities and load-serving entities in proportion to their contribution to unreliability during the times of highest reliability risk due to low operating reserves by season, as determined by the commission based on a number of hours adopted by the commission for that season; or

(2) using another method identified by the commission.

(c) The evaluation must:

(1) use historical ancillary and reliability services data;

(2) consider the causes for ancillary services deployments; and

(3) consider the design, procurement, and cost allocation of ancillary services required by Section 35.004(h).

(d) Not later than December 1, 2026, the commission shall submit a report on the evaluation to the legislature.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 23, eff. September 1, 2023.

Sec. 39.1594. RELIABILITY PROGRAM. (a) Under Section 39.159(b), as added by Chapter 426 (S.B. 3), Acts of the 87th Legislature, Regular Session, 2021, or other law, the commission may not require retail customers or load-serving entities in the ERCOT power region to purchase credits designed to support a required reserve margin or other capacity or reliability requirement unless the commission ensures that:

(1) the net cost to the ERCOT market of the credits does not exceed $1 billion annually, less the cost of any interim or bridge solutions that are lawfully implemented, except that the commission may adjust the limit:

(A) proportionally according to the highest net peak demand year-over-year with a base year of 2026; and

(B) for inflation with a base year of 2026;

(2) credits are available only for dispatchable generation;

(3) the independent organization certified under Section 39.151 for the ERCOT power region is required to procure the credits centrally in a manner designed to prevent market manipulation by affiliated generation and retail companies;

(4) a generator cannot receive credits that exceed the amount of generation bid into the forward market by that generator;

(5) an electric generating unit can receive a credit only for being available to perform in real time during the tightest intervals of low supply and high demand on the grid, as defined by the commission on a seasonal basis;

(6) a penalty structure is established, resulting in a net benefit to load, for generators that bid into the forward market but do not meet the full obligation;

(7) any program reliability standard reasonably balances the incremental reliability benefits to customers against the incremental costs of the program based on an evaluation by the wholesale electric market monitor;

(8) a single ERCOT-wide clearing price is established for the program and does not differentiate payments or credit values based on locational constraints;

(9) any market changes implemented as a bridge solution for the program are removed not later than the first anniversary of the date the program was implemented;

(10) the independent organization certified under Section 39.151 for the ERCOT power region begins implementing real time co-optimization of energy and ancillary services in the ERCOT wholesale market before the program is implemented;

(11) all elements of the program are initially implemented on a single starting date;

(12) the terms of the program and any associated market rules do not assign costs, credit, or collateral for the program in a manner that provides a cost advantage to load-serving entities who own, or whose affiliates own, generation facilities;

(13) secured financial credit and collateral

requirements are adopted for the program to ensure that other market participants do not bear the risk of nonperformance or nonpayment; and

(14) the wholesale electric market monitor has the authority and necessary resources to investigate potential instances of market manipulation by program participants, including financial and physical actions, and recommend penalties to the commission.

(b) This section does not require the commission to adopt a reliability program that requires an entity to purchase capacity credits.

(c) The commission and the independent organization certified under Section 39.151 for the ERCOT power region shall consider comments and recommendations from a technical advisory committee established under the bylaws of the independent organization that includes market participants when adopting and implementing a program described by Subsection (a), if any.

(d) Before the commission adopts a program described by Subsection (a), the commission shall require the independent organization certified under Section 39.151 for the ERCOT power region and the wholesale electric market monitor to complete an updated assessment on the cost to and effects on the ERCOT market of the proposed reliability program and submit to the commission and the legislature a report on the costs and benefits of continuing the program. The assessment must include:

(1) an evaluation of the cost of new entry and the effects of the proposed reliability program on consumer costs and the competitive retail market;

(2) a compilation of detailed information regarding cost offsets realized through a reduction in costs in the energy and ancillary services markets and use of reliability unit commitments;

(3) a set of metrics to measure the effects of the proposed reliability program on system reliability;

(4) an evaluation of the cost to retain existing dispatchable resources in the ERCOT power region;

(5) an evaluation of the planned timeline for implementation of real time co-optimization for energy and

ancillary services in the ERCOT power region; and

(6) anticipated market and reliability effects of new and updated ancillary service products.

(e) If the commission adopts a program described by Subsection (a), the commission by rule shall prohibit a generator that receives credits through the program for a dispatchable electric generating unit operated by the generator from decommissioning or removing from service that unit while the generator participates in the program unless the decommissioning or removal from service begins after September 1, 2028, or the commission finds that the decommissioning or removal from service:

(1) is required by or is a result of federal law; or

(2) would alleviate significant financial hardship for the generator.

(f) If the commission adopts a program described by Subsection (a), the wholesale electric market monitor described by Section 39.1515 biennially shall:

(1) evaluate the incremental reliability benefits of the program for consumers compared to the costs to consumers of the program and the costs in the energy and ancillary services markets; and

(2) report the results of each evaluation to the legislature.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 23, eff. September 1, 2023.

Sec. 39.1595. GRID RELIABILITY LEGISLATIVE OVERSIGHT COMMITTEE. (a) In this section, "committee" means the Grid Reliability Legislative Oversight Committee established under this section.

(b) The Grid Reliability Legislative Oversight Committee is created to oversee the commission's implementation of legislation related to the regulation of the electricity market in this state enacted by the 87th and 88th Legislatures.

(c) The committee is composed of eight members as follows:

(1) three members of the senate, appointed by the lieutenant governor;

(2) three members of the house of representatives, appointed by the speaker of the house of representatives;

(3) the chair of the committee of the senate having primary jurisdiction over matters relating to the generation of electricity; and

(4) the chair of the committee of the house having primary jurisdiction over matters relating to the generation of electricity.

(d) An appointed member of the committee serves at the pleasure of the appointing official.

(e) The committee members described by Subsections (c)(3) and (4) serve as presiding co-chairs.

(f) A member of the committee may not receive compensation for serving on the committee but is entitled to reimbursement for travel expenses incurred by the member while conducting the business of the committee as provided by the General Appropriations Act.

(g) The committee shall meet at least twice each year at the call of either co-chair and shall meet at other times at the call of either co-chair, as that officer determines appropriate.

(h) Chapter 551, Government Code, applies to the committee.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 23, eff. September 1, 2023.

Text of section as added by Acts 2021, 87th Leg., R.S., Ch. 426 (S.B. 3), Sec. 18

For text of section as added by Acts 2021, 87th Leg., R.S., Ch. 950 (S.B. 1580), Sec. 3, see other Sec. 39.160.

Sec. 39.160. WHOLESALE PRICING PROCEDURES. (a) The commission by rule shall establish an emergency pricing program for the wholesale electric market.

(b) The emergency pricing program must take effect if the high system-wide offer cap has been in effect for 12 hours in a 24-hour period after initially reaching the high system-wide offer cap. The commission by rule shall determine the criteria for the emergency pricing program to cease.

(c) The emergency pricing program may not allow an emergency pricing program cap to exceed any nonemergency high system-wide offer cap.

(d) The commission by rule shall establish an ancillary services cap to be in effect during the period an emergency pricing program is in effect.

(e) Any wholesale pricing procedure that has a low system-wide offer cap may not allow the low system-wide offer cap to exceed the high system-wide offer cap.

(f) The commission shall review each system-wide offer cap program adopted by the commission, including the emergency pricing program, at least once every five years to determine whether to update aspects of the program.

(g) The emergency pricing program must allow generators to be reimbursed for reasonable, verifiable operating costs that exceed the emergency cap.

Added by Acts 2021, 87th Leg., R.S., Ch. 426 (S.B. 3), Sec. 18, eff. June 8, 2021.

Sec. 39.161. CHARGES FOR CERTAIN MARKET PARTICIPANTS. Notwithstanding any other law, no default or uplift charge or repayment may be allocated to or collected from a market participant that:

(1) otherwise would be subject to an uplift charge solely as a result of acting as a central counterparty clearinghouse in wholesale market transactions in the ERCOT power region; and

(2) is regulated as a derivatives clearing organization, as defined by the Commodity Exchange Act (7 U.S.C. Section 1a).

Added by Acts 2021, 87th Leg., R.S., Ch. 950 (S.B. 1580), Sec. 3, eff. June 18, 2021.

Redesignated from Utilities Code, Section 39.159 by Acts 2023, 88th Leg., R.S., Ch. 768 (H.B. 4595), Sec. 22.003(b), eff. September 1, 2023.

Sec. 39.162. DEFAULT OF MARKET PARTICIPANT. (a) The commission shall require that all market participants pay or make provision for the full and prompt payment of amounts owed calculated solely according to the protocols in effect during the period of emergency to the independent organization certified under Section 39.151 for the ERCOT power region to qualify, or to continue to qualify, as a market participant in the ERCOT power region.

(b) If a market participant has failed to fully repay all amounts calculated solely under the protocols in effect during the period of emergency of the independent organization certified under Section 39.151 for the ERCOT power region, the independent organization shall report the market participant as in default to the commission. The commission may not allow the independent organization to accept the defaulting market participant's loads or generation for scheduling in the ERCOT power region, or allow the defaulting market participant to be a market participant in the ERCOT power region for any purpose, until all amounts owed to the independent organization by the market participant as calculated under the protocols are paid in full.

(c) The commission and the independent organization certified under Section 39.151 for the ERCOT power region shall pursue collection in full of amounts owed to the independent organization by the defaulting market participant.

Added by Acts 2021, 87th Leg., R.S., Ch. 950 (S.B. 1580), Sec. 3, eff. June 18, 2021.

Redesignated from Utilities Code, Section 39.160 by Acts 2023, 88th Leg., R.S., Ch. 768 (H.B. 4595), Sec. 22.003(b), eff. September 1, 2023.

Sec. 39.163. AMOUNTS OWED TO INDEPENDENT ORGANIZATION BY MARKET PARTICIPANTS. (a) The commission shall require that all market participants fully and promptly pay to the independent organization certified under Section 39.151 for the ERCOT power region all amounts owed to the independent organization, or provide for the full and prompt payment of those amounts owed, which must be calculated solely according to the protocols of the independent organization in effect during the period of emergency and subject to the jurisdiction of the commission, to qualify, or to continue to qualify, as a market participant in the ERCOT power region.

(b) The independent organization shall report to the commission that a market participant is in default for the failure to pay, or provide for the full and prompt payment of, all amounts owed to the independent organization as calculated in accordance with this section. The commission may not allow the defaulting market participant to continue to be a market participant in the ERCOT power region for any purpose or allow the independent organization to accept the defaulting market participant's loads or generation for scheduling in the ERCOT power region until all amounts owed to the independent organization by the market participant as calculated in this section are fully paid.

(c) The commission and the independent organization shall pursue collection in full of amounts owed to the independent organization by any market participant to reduce the costs that would otherwise be borne by other market participants or their customers.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 4, eff. June 16, 2021.

Redesignated from Utilities Code, Section 39.159 by Acts 2023, 88th Leg., R.S., Ch. 768 (H.B. 4595), Sec. 22.003(c), eff. September 1, 2023.

Sec. 39.164. AUDIT OF INDEPENDENT ORGANIZATION CERTIFIED FOR ERCOT POWER REGION. (a) The commission annually shall have an independent audit made of each independent organization certified under Section 39.151 for the ERCOT power region.

(b) An audit under this section must examine:

(1) the independent organization's financial condition, including the organization's budget and expenses, and the salaries of the organization's employees and board members; and

(2) compliance of the independent organization's assets with all applicable commission standards.

(c) Not later than the 60th day after the date an audit under this section is completed the commission shall:

(1) publish the results of the audit on the commission's Internet website; and

(2) submit the results of the audit to the state

auditor and members of the standing committees of the legislature with primary jurisdiction over the commission.

Added by Acts 2021, 87th Leg., R.S., Ch. 73 (H.B. 2586), Sec. 1, eff. September 1, 2021.

Redesignated from Utilities Code, Section 39.159 by Acts 2023, 88th Leg., R.S., Ch. 768 (H.B. 4595), Sec. 22.003(d), eff. September 1, 2023.

Sec. 39.165. GRID RELIABILITY ASSESSMENT. (a) The independent organization certified under Section 39.151 for the ERCOT power region shall conduct a biennial assessment of the ERCOT power grid to assess the grid's reliability in extreme weather scenarios.

(b) Each assessment must:

(1) consider the impact of different levels of thermal and renewable generation availability; and

(2) recommend transmission projects that may increase the grid's reliability in extreme weather scenarios.

Added by Acts 2021, 87th Leg., R.S., Ch. 876 (S.B. 1281), Sec. 3, eff. September 1, 2021.

Redesignated from Utilities Code, Section 39.159 by Acts 2023, 88th Leg., R.S., Ch. 768 (H.B. 4595), Sec. 22.003(e), eff. September 1, 2023.

Text of section as added by Acts 2023, 88th Leg., R.S., Ch. 892 (H.B. 5066), Sec. 3

For text of section as added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 24(b), see other Sec. 39.166.

Sec. 39.166. RELIABILITY PLAN FOR REGIONS WITH RAPID ELECTRICAL LOAD GROWTH. (a) The commission shall direct the independent organization certified under Section 39.151 for the ERCOT power region to:

(1) identify each region in which transmission capacity is insufficient to meet the region's existing and forecasted electrical load, as reasonably determined by the certificated transmission service provider; and

(2) develop a reliability plan to serve existing and

forecasted electrical load in the identified region.

(b) The commission shall develop a plan to implement each reliability plan adopted under Subsection (a) to ensure timely development and approval of necessary transmission service improvements.

Added by Acts 2023, 88th Leg., R.S., Ch. 892 (H.B. 5066), Sec. 3, eff. June 13, 2023.

Text of section as added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 24

For text of section as added by Acts 2023, 88th Leg., R.S., Ch. 892 (H.B. 5066), Sec. 3, see other Sec. 39.166.

Sec. 39.166. ELECTRIC INDUSTRY REPORT. (a) Not later than January 15 of each odd-numbered year, the commission, in consultation with the independent organization certified under Section 39.151 for the ERCOT power region, shall prepare and submit to the legislature an electric industry report.

(b) Each electric industry report submitted under this section must:

(1) identify existing and potential transmission and distribution constraints and system needs within the ERCOT power region, alternatives for meeting system needs, and recommendations for meeting system needs;

(2) summarize key findings from:

(A) the grid reliability assessment conducted under Section 39.165; and

(B) the report required by Section 39.9112;

(3) outline basic information regarding the electric grid and market in this state, including generation capacity, customer demand, and transmission capacity currently installed on the grid and projected in the future; and

(4) be presented in plain language that is readily understandable by a person with limited knowledge of the electric industry.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 24(b), eff. September 1, 2023.

Text of section as added by Acts 2023, 88th Leg., R.S., Ch. 892 (H.B. 5066), Sec. 3

For text of section as added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 24(b), see other Sec. 39.167.

For expiration of this section, see Subsection (c).

Sec. 39.167. RELIABILITY PLAN FOR PERMIAN BASIN. (a) Not later than January 30, 2024, the commission shall direct the independent organization certified under Section 39.151 for the ERCOT power region to develop a reliability plan under Section 39.166 for the Permian Basin region.

(b) The plan must:

(1) address extending transmission service to areas where mineral resources have been found;

(2) address increasing available capacity to meet forecasted load; and

(3) provide available infrastructure to reduce interconnection times in areas without access to transmission service.

(c) This section expires September 1, 2025.

Added by Acts 2023, 88th Leg., R.S., Ch. 892 (H.B. 5066), Sec. 3, eff. June 13, 2023.

Text of section as added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 24

For text of section as added by Acts 2023, 88th Leg., R.S., Ch. 892 (H.B. 5066), Sec. 3, see other Sec. 39.167.

Sec. 39.167. CONFLICTS OF INTEREST REPORT. The commission and the independent organization certified under Section 39.151 for the ERCOT power region annually shall review statutes, rules, protocols, and bylaws that apply to conflicts of interest for commissioners and for members of the governing body of the independent organization and submit to the legislature a report on the effects the statutes, rules, protocols, and bylaws have on the ability of the commission and the independent organization to fulfill their duties.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 24(b), eff. September 1, 2023.

Sec. 39.168. RETAIL SALES REPORT. (a) Each retail electric provider that offers electricity for sale shall report to the commission:

(1) its annual retail sales in this state;

(2) the annual retail sales of its affiliates by number of customers, kilowatts per hour sold, and revenue from kilowatts per hour sold by customer class; and

(3) any other information the commission requires relating to affiliations between retail electric providers.

(b) The commission by rule shall prescribe the nature and detail of the reporting requirements. The commission may accept information reported under other law to satisfy the requirements of this section. Information reported under this section is confidential and not subject to disclosure if the information is competitively sensitive information. The commission shall administer the reporting requirements in a manner that ensures the confidentiality of competitively sensitive information.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 24(b), eff. September 1, 2023.

SUBCHAPTER E. PRICE REGULATION AFTER COMPETITION

Sec. 39.201. COST OF SERVICE TARIFFS AND CHARGES. (a) Each electric utility shall, on or before April 1, 2000, file proposed tariffs for its proposed transmission and distribution utility.

(b) The filing under this section shall include supporting cost data for determination of nonbypassable delivery charges, which shall be the sum of:

(1) transmission and distribution utility charges by customer class based on a forecasted 2002 test year;

(2) a system benefit fund fee; and

(3) an expected competition transition charge, if any.

(c) Each electric utility shall also identify the unbundled generation and retail energy service costs by customer class.

(d) In accordance with a schedule and procedures it establishes, the commission shall hold a hearing and approve or modify and make effective as of January 1, 2002, the transmission and distribution utility's proposed tariffs for transmission and distribution services, the system benefit fund fee, and the expected competition transition charge as determined under Subsections (g) and (h) and as implemented under Subsections (i)-(l), if any.

(e) The system benefit fund fee shall be that established by the commission under Section 39.903.

(f) The expected competition transition charge shall be that as determined under Subsections (g) and (h) and as implemented under Subsections (i)-(l).

(g) The expected competition transition charge approved by the commission shall be calculated from the amount of stranded costs as defined in Subchapter F that are reasonably projected to exist on the last day of the freeze period modified to reflect any adjustments determined appropriate by the commission under Section 39.261(c).

(h) The electric utility shall use the ECOM administrative model referenced in Section 39.262 to determine estimated stranded costs. The model must include updated company-specific inputs. Natural gas prices used in the model must be market-based natural gas forward prices, where available. 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. Capital additions shall be benchmarked using the limitation in Section 39.259(b).

(i) An electric utility may:

(1) at any time after the start of the freeze period, securitize 100 percent of its regulatory assets as defined by Section 39.302 and up to 75 percent of its estimated stranded costs as defined by this section and recover those charges through a transition charge, in accordance with a financing order issued by the commission under Section 39.303;

(2) implement, under bond, a nonbypassable charge of up to 100 percent of its estimated stranded costs; or

(3) use a combination of the two methods under

Subdivisions (1) and (2).

(j) Any competition transition charge shall be allocated among retail customer classes according to Section 39.253.

(k) In determining the length of time over which stranded costs under Subsection (h) may be recovered, the commission shall consider:

(1) the electric utility's rates as of the end of the freeze period;

(2) the sum of the transmission and distribution charges and the system benefit fund fees;

(3) the proportion of estimated stranded costs to the invested capital of the electric utility; and

(4) any other factor consistent with the public interest as expressed in this chapter.

(l) Two years after customer choice is introduced, the stranded cost estimate under this section shall be reviewed and, if necessary, adjusted to reflect a final, actual valuation in the true-up proceeding under Section 39.262. If, based on that proceeding, the competition transition charge is not sufficient, the commission may extend the collection period for the charge or, if necessary, increase the charge. Alternatively, if it is found in the true-up proceeding that the competition transition charge is larger than is needed to recover any remaining stranded costs, the commission may:

(1) reduce the competition transition charge, to the extent it has not been securitized;

(2) reverse, in whole or in part, the depreciation expense that has been redirected under Section 39.256;

(3) reduce the transmission and distribution utility's rates; or

(4) implement a combination of the elements in Subdivisions (1)-(3).

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.202. PRICE TO BEAT. (a) From January 1, 2002, until January 1, 2007, an affiliated retail electric provider shall make available to residential and small commercial customers of its affiliated transmission and distribution utility rates that, on a bundled basis, are six percent less than the affiliated electric utility's corresponding average residential and small commercial rates, on a bundled basis, that were in effect on January 1, 1999, adjusted to reflect the fuel factor determined as provided by Subsection (b) 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. These rates on a bundled basis shall be known as the "price to beat" for residential and small commercial customers, except that the "price to beat" for a utility is the rate in effect as a result of a settlement approved by the commission after January 1, 1999, if the commission determines that base rates for that utility have been reduced by more than 12 percent as a result of a final order issued by the commission after October 1, 1998.

(b) The commission shall determine the fuel factor for each electric utility as of December 31, 2001.

(c) After the date of customer choice, each affiliated power generation company shall file a final fuel reconciliation for the period ending the day before the date customer choice is introduced. The final fuel balance from that reconciliation shall be included in the true-up proceeding under Section 39.262.

(d) An affiliated retail electric provider shall make public its price to beat in a manner that provides adequate disclosure as determined by the commission.

(e) The affiliated retail electric provider may not charge rates for residential or small commercial customers that are different from the price to beat until the earlier of 36 months after the date customer choice is introduced or:

(1) for service to residential customers, the date the commission determines that 40 percent or more of the electric power consumed by residential customers within the affiliated transmission and distribution utility's certificated service area before the onset of customer choice is committed to be served by nonaffiliated retail electric providers; or

(2) for service to small commercial customers, the date the commission determines that 40 percent or more of the

electric power consumed by small commercial customers within the affiliated transmission and distribution utility's certificated service area before the onset of customer choice is committed to be served by nonaffiliated retail electric providers.

(f) Notwithstanding Subsection (e), the affiliated retail electric provider may charge rates that are different from the price to beat for service to aggregated loads of nonresidential customers having an aggregated peak demand greater than 1,000 kilowatts, provided that all affected customers are:

(1) commonly owned; or

(2) franchisees of the same franchisor.

(g) The affiliated retail electric provider may not encourage or provide an incentive to a customer to switch to a nonaffiliated retail electric provider, promote any nonaffiliated retail electric provider, or exchange customers with any nonaffiliated retail electric provider to comply with the requirements of Subsection (e)(1) or (2).

(h) The following standards shall be used for measuring electric power consumption during the period before the onset of customer choice:

(1) the consumption of residential and small commercial customers with an annual peak demand less than or equal to 20 kilowatts shall be based on the average annual consumption of those respective groups during the year 2000;

(2) consumption for all small commercial customers with an annual peak demand larger than 20 kilowatts shall be based on each customer's usage during the year 2000; and

(3) for purposes of determining whether an affiliated retail electric provider has met the requirements of Subsection (e)(2), the aggregated loads of nonresidential customers having a peak demand greater than 1,000 kilowatts that are served by the affiliated retail electric provider at a rate different from the price to beat under Subsection (f) shall be deducted from the electric power consumption of small commercial customers during the period before the onset of customer choice.

(i) For purposes of Subsection (h)(2), if less than 12 months of consumption history exists for any such customer, the usage history shall be supplemented with the prior history of that customer's location. For service to a new location, the annual consumption shall be determined as the transmission and distribution utility's estimate of the maximum annual kilowatt demand used in sizing the electric service to that customer multiplied by 8,760 hours, and that product multiplied by the average annual customer load factor for small commercial customers with loads greater than 20 kilowatts for the year 2000.

(j) On determining that its affiliated retail electric provider has met the requirements of Subsection (e)(1) or (2), an electric utility or a transmission and distribution utility shall make a filing with the commission attesting to the fact that those requirements have been met and that the restrictions of Subsection (e)(1) or (2) and the true-up in Section 39.262(e) are no longer applicable. The commission shall adopt appropriate procedures to enable it to accept or reject the filing within 30 days.

(k) Following the true-up proceedings conducted under Section 39.262, the commission may adjust the price to beat.

(l) An affiliated retail electric provider may request that the commission adjust the fuel factor established under Subsection (b) not more than twice a year if the affiliated retail electric provider demonstrates that the existing fuel factor does not adequately reflect significant changes in the market price of natural gas and purchased energy used to serve retail customers.

(m) In a power region outside of ERCOT, if customer choice is introduced before the requirements of Section 39.152(a) are met, an affiliated retail electric provider shall charge rates to customers other than residential and small commercial customers that are no higher than the rates that, on a bundled basis, were in effect on January 1, 1999, adjusted to reflect the fuel factor as provided by Subsection (b) 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.

(n) Notwithstanding Subsection (a), in a power region outside of ERCOT, if customer choice is introduced before the requirements of Section 39.152(a) are met, an affiliated retail electric provider shall continue to offer the price to beat to residential and small commercial customers, unless the price is changed by the commission in accordance with this chapter, until the later of 60 months after the date customer choice is introduced or the requirements of Section 39.152(a) are met.

(o) In this section, "small commercial customer" means a commercial customer having a peak demand of 1,000 kilowatts or less.

(p) On finding that a retail electric provider will be unable to maintain its financial integrity if it complies with Subsection (a), the commission shall set the retail electric provider's price to beat at the minimum level that will allow the retail electric provider 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 as provided by Subsection (b).

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.203. TRANSMISSION AND DISTRIBUTION SERVICE. (a) All transmission and distribution utilities shall provide transmission service at wholesale under Subchapter A, Chapter 35. In addition, on and after January 1, 2002, a transmission and distribution utility shall provide transmission or distribution service, or both, at retail to an electric utility, a retail electric provider, a municipally owned utility, an electric cooperative, or an end-use customer at rates, terms of access, and conditions that are comparable to those that apply to the transmission and distribution utility and its affiliates. A municipally owned utility offering customer choice or an electric cooperative offering customer choice shall likewise provide transmission or distribution service, or both, at retail to all such entities in accordance with the commission's rules applicable to terms and conditions of access and at rates adopted in accordance with Sections 40.055(a)(1) and 41.055(1), respectively.

(b) When necessary to serve a wholesale customer an electric utility, 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. A customer of a municipally owned utility that has not opted for customer choice or of an electric cooperative that has not opted for customer choice may not claim the status of a wholesale customer or be designated as a wholesale customer if the customer is being or has been served under a retail rate schedule of the municipally owned utility or electric cooperative.

(c) On or before January 1, 2002, the commission shall establish for all retail electric utilities offering customer choice reasonable and comparable terms and conditions, in accordance with Section 39.201, that comply with Subsection (a) for open access on distribution facilities and shall establish, for all retail electric utilities offering customer choice other than municipally owned utilities and electric cooperatives, reasonable and comparable rates for open access on distribution facilities.

(d) The terms of access, conditions, and rates established under Subsection (c) shall be comparable to the terms of access, conditions, and rates that the electric utility applies to itself or its affiliates. The rules shall also provide that all ancillary services provided by the utility to itself or its affiliates are also available to third parties on request on a nondiscriminatory basis.

(e) The commission may require an electric utility or a transmission and distribution utility to construct or enlarge 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. In any proceeding brought under Chapter 37, an electric utility or transmission and distribution utility ordered to construct or enlarge facilities under this subchapter need not prove that the construction ordered is necessary for the service, accommodation, convenience, or safety of the public and need not address the factors listed in Sections 37.056(c)(1)-(3) and (4)(E). Notwithstanding any other law, including Section 37.057, in any proceeding brought under Chapter 37 by an electric utility or a transmission and distribution utility related to an application for a certificate of public convenience and necessity to construct or enlarge transmission or transmission-related facilities under this subsection, the commission shall issue a final order before the 181st day after the date the application is filed with the commission. If the commission does not issue a final order before that date, the application is approved.

(f) The commission's rules must be consistent with the standards of this title and may not be contrary to an applicable decision, rule, or policy statement of a federal regulatory agency having jurisdiction.

(g) Each power region shall have generally applicable tariffs approved by the commission or a federal regulatory agency having jurisdiction that guarantees open and nondiscriminatory access as required by Section 39.152. This subsection may not be deemed to vest in the commission power to set or approve distribution access rates of a municipally owned utility or an electric cooperative that has adopted customer choice.

(h) A customer in a multiply certificated service area may switch its retail distribution service provider among certificated retail electric utilities only by disconnecting from the facilities of one retail electric utility and connecting to the facilities of another retail electric utility.

(i) The commission, in cooperation with transmission and distribution utilities and the ERCOT independent system operator, shall study whether existing transmission and distribution planning processes are sufficient to provide adequate infrastructure for seawater desalination projects. If the commission determines that statutory changes are needed to ensure that adequate infrastructure is developed for projects of that kind, the commission shall include recommendations in the report required by Section 12.203.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999. Amended by Acts 2003, 78th Leg., ch. 295, Sec. 3, eff. June 18, 2003.

Amended by:

Acts 2005, 79th Leg., 1st C.S., Ch. 1 (S.B. 20), Sec. 2, eff.

September 1, 2005.

Acts 2015, 84th Leg., R.S., Ch. 829 (H.B. 4097), Sec. 1, eff. June 17, 2015.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 26, eff. September 1, 2023.

Sec. 39.204. TARIFFS FOR OPEN ACCESS. Each transmission and distribution utility shall file a tariff implementing the open access rules with the commission or the federal regulatory authority having jurisdiction over the transmission and distribution service of the utility not later than the 90th day before the date customer choice is offered by that utility.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.205. REGULATION OF COSTS FOLLOWING FREEZE PERIOD. At the conclusion of the freeze period, any remaining costs associated with nuclear decommissioning obligations continue to be subject to cost of service rate regulation and shall be included as a nonbypassable charge to retail customers. The commission may adopt rules necessary to ensure that money for decommissioning is prudently collected, managed, and spent for its intended purpose and that money that remains unspent after decommissioning is completed is returned to retail customers.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.
Amended by:

Acts 2005, 79th Leg., Ch. 121 (S.B. 1464), Sec. 2, eff. September 1, 2005.

Sec. 39.206. NUCLEAR GENERATING UNIT DECOMMISSIONING COST PLAN. (a) For purposes of this section:

(1) "Decommissioning" includes decommissioning and decontamination of a nuclear generating unit consistent with federal Nuclear Regulatory Commission requirements.

(2) "Nuclear decommissioning trust" means an external and irrevocable trust created for the purpose of funding decommissioning obligations for a nuclear generating unit, consistent with federal Nuclear Regulatory Commission

requirements.

(3) "Nuclear generating unit" means an electric generating facility that uses nuclear energy to generate electricity for sale and is licensed by the Nuclear Regulatory Commission.

(4) "Power generation company" has the meaning assigned by Section 31.002.

(5) "Retail electric customer" means a retail electric customer:

(A) in a geographic area of this state in which retail customer choice has been implemented; or

(B) of a municipally owned utility or electric cooperative that has an agreement to purchase power from a nuclear generating unit.

(b) This section applies only to the first six nuclear generating units the construction of which begins on or after January 1, 2013, and before January 1, 2033, and which are owned in whole or in part by a power generation company that elects to utilize the decommissioning mechanism set forth in this section.

(c) Nothing in this section shall be construed to require a power generation company to use a commission approved method to provide funds for decommissioning, if the power generation company can otherwise satisfy the decommissioning financial assurance requirements of the federal Nuclear Regulatory Commission.

(d) A power generation company that owns a nuclear generating unit shall fund out of operating revenues on an annual basis:

(1) the costs associated with funding the decommissioning obligations for the nuclear generating unit; or

(2) the power generation company's portion of the decommissioning costs for the nuclear generating unit in proportion to the company's ownership interest in the nuclear generating unit if the unit is owned by more than one person.

(e) The obligation to fund a nuclear decommissioning trust fund is not dischargeable in bankruptcy.

(f) A power generation company shall establish a nuclear decommissioning trust for a nuclear generating unit it owns or for the proportionate share of a nuclear generating unit of which it owns a part. The funding obligations for the trust must begin before the nuclear generating unit commences its initial fuel load and begins commercial operation to generate power for sale. The terms of the trust must be consistent with trust terms and conditions the federal Nuclear Regulatory Commission requires for providing financial assurance for decommissioning.

(g) The commission by order shall establish for a nuclear generating unit the amount of annual decommissioning 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 power generation company. The power generation company shall perform a study on the cost of decommissioning to establish the decommissioning obligations before the nuclear generating unit begins commercial operation to generate power for sale. The study shall be performed by the power generation company at least once in each three-year period during the unit's operating license period using the most current reasonably available information on the cost of decommissioning. The commission shall conduct a proceeding at least once in each three-year period to review the study and other current reasonably available information on the cost of decommissioning and determine the reasonableness of the study.

(h) A power generation company shall file an annual report to provide the status of the decommissioning trust fund and to update the commission as to its ability to fund the decommissioning trust fund. In determining the amount of the annual decommissioning funding under this subsection, at least once in each three-year period, the commission shall conduct a proceeding to review the balance of each nuclear decommissioning trust and the projected amount of annual decommissioning funding for the associated nuclear generating unit. On the conclusion of the review proceeding, the commission by order shall revise the amount of annual funding for the nuclear generating unit in order to ensure that the nuclear decommissioning trust fund is adequately funded.

(i) A power generation company shall remit the appropriate amount of annual decommissioning funding to the nuclear decommissioning trust created for its proportionate ownership position in a nuclear generating unit in accordance with the commission's funding order issued under Subsection (g) or (h). The commission shall take appropriate actions to ensure proper funding of the nuclear decommissioning trust, including possibly terminating the power generation company's registration to operate, if the company violates this subsection.

(j) A power generation company that owns a nuclear generating unit is the funds administrator of the nuclear decommissioning trust for the associated nuclear generating unit. The company, as funds administrator, shall invest the trust funds in accordance with guidelines established by commission rule and consistent with the federal Nuclear Regulatory Commission guidelines so that the decommissioning funds, plus the amounts earned from investment of the funds, will be available at the time of decommissioning. The commission shall adopt rules to define the company's specific duties as funds administrator and requirements regarding prudent management and investment of nuclear decommissioning trust funds.

(k) The commission shall adopt rules necessary to ensure that:

(1) a power generation company remits sufficient funds to a nuclear decommissioning trust on an annual basis, including projected earnings to approximate the amount remaining to be accumulated to cover the cost of decommissioning a nuclear generating unit at the end of its operating license period divided by the remaining years of the license and in accordance with applicable state and federal laws and regulations or over a shorter period of time at the election of the power generation company;

(2) the periodic cost studies and reviews described in Subsections (g) and (h) include all current reasonably available information as determined necessary and appropriate by the commission;

(3) all funds remitted to a nuclear decommissioning trust are prudently managed and spent for their intended purpose;

(4) the funds remitted to a nuclear decommissioning

trust and the amounts earned from investing the funds, will be available for, and restricted to the purpose of decommissioning of the associated nuclear generating unit, including if the trust or nuclear generating unit is transferred to another person; and

(5) before a power generation company is allowed to take advantage of the mechanisms in this section, the company meets creditworthiness standards established by the commission to minimize the risk that retail electric customers will be responsible for funding any shortfall in the cost of decommissioning a nuclear generating unit.

(l) In addition to the nuclear decommissioning trust required by Subsection (f), for purposes of Subsection (k), the power generation company and its parent and affiliates shall provide financial assurances that funds will be available to satisfy up to 16 years of annual decommissioning funding in the event the power generation company defaults on its obligation to make annual funding to the decommissioning trust. Within 180 days after the effective date of this section, the commission by rule shall establish the acceptable forms of financial assurance, which shall include, but not be limited to, parent guarantees and support agreements, letters of credit, surety or insurance, and such other requirements necessary to ensure compliance with this section. In establishing the acceptable forms of assurance, and the eligibility requirements for each form of assurance, the commission shall consider the relative risk factors and creditworthiness attributes of potential applicant financial characteristics in order to minimize exposure of retail electric customers to default by power generation companies under this section. The power generation company may choose the manner of financial assurance for which it is eligible under the commission's rules.

(m) In the event the financial assurances provided by Subsection (k) are insufficient to meet the annual funding requirements of the decommissioning trust, the retail electric customers shall be responsible for funding any shortfall in the cost of decommissioning the nuclear generating unit.

(n) 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, consistent with law.

(o) 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 the nuclear generating unit generated.

(p) If retail electric customers in this state become responsible for the costs of decommissioning a nuclear generating unit and incur costs under this section and the nuclear generating unit is operational, as a condition of operating the generating unit, the power generation company or any new owner shall repay the costs the electric customers incurred in the manner determined by the commission. The commission may authorize the repayment to occur over a period established by the commission.

(q) The commission shall, in conjunction with the Nuclear Regulatory Commission, investigate the development of a mechanism whereby the State of Texas could ensure that funds for decommissioning will be obtained when necessary in the same manner as if the State of Texas were the licensee under federal law.

(r) The commission by rule shall ensure that:

(1) money for decommissioning a nuclear generating unit is prudently collected, managed, and spent for its intended purposes; and

(2) decommissioning money that remains unspent after decommissioning of the nuclear generating unit is complete is returned to the power generation company and the retail electric customers based on the proportionate amount of money the power generation company and retail electric customers paid into the fund.

Added by Acts 2007, 80th Leg., R.S., Ch. 1019 (H.B. 1386), Sec. 1, eff. September 1, 2007.

Amended by:

Acts 2013, 83rd Leg., R.S., Ch. 55 (H.B. 994), Sec. 1, eff. May 18, 2013.

Acts 2013, 83rd Leg., R.S., Ch. 55 (H.B. 994), Sec. 2, eff. May 18, 2013.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 27, eff. September 1, 2023.

SUBCHAPTER F. RECOVERY OF STRANDED COSTS THROUGH COMPETITION TRANSITION CHARGE

Sec. 39.251. DEFINITIONS. In this subchapter:

(1) "Above market purchased power costs" means 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) "Existing purchased power contract" means 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.

(3) "Generation assets" means 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.

(4) "Market value" means, 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 Section 39.262(h) or, for certain nuclear assets, as described by Section 39.262(i), the value determined under the method provided by that subsection.

(5) "Purchased power market value" means 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.

(6) "Retail stranded costs" means that part of net stranded cost associated with the provision of retail service.

(7) "Stranded cost" means 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 No. 71 ("Accounting for the Effects of Certain Types of Regulation") for generation-related assets if required by the provisions of this chapter. For purposes of Section 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 Section 39.262(h), whichever is earlier, and shall include stranded costs incurred under Section 39.263.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.252. RIGHT TO RECOVER STRANDED COSTS. (a) An electric utility is allowed to recover all of its net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service.

(b)(1) 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 new on-site generation except as provided by Section 39.262(k). For purposes of this subchapter, "new on-site generation" means electric generation capacity greater than 10 megawatts capable of being lawfully delivered to the site without use of utility distribution or transmission facilities and 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 in effect at the time of filing.

(2) If a customer commences taking energy from new on-site generation which materially reduces the customer's use of energy delivered through the utility's facilities, the customer shall pay an amount each month computed by multiplying the output of the on-site generation by the new sum of competition transition charges under Section 39.201 and transition charges under Subchapter G which are in effect during that month. Payment shall be made to the utility, its successors, an assignee, or other collection agent responsible for collecting the competition transition charges and transition charges and shall be collected in addition to the competition transition charges and transition charges applicable to energy actually delivered to the customer through the utility's facilities.

(c) 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. A customer in a multiply certificated service area that requested to switch providers on or before May 1, 1999, or was not taking service from an electric utility on May 1, 1999, and does not do so after that date is not responsible for paying retail stranded costs of that utility.

(d) An electric utility shall pursue commercially reasonable means to reduce its potential stranded costs, including good faith attempts to renegotiate above-cost fuel and purchased power contracts or the exercise of normal business practices to protect the value of its assets. The commission shall consider the utility's efforts under this subsection when determining the amount of the utility's stranded costs; provided, however, that nothing in this section authorizes the commission to substitute its judgment for a market valuation of generation assets determined under Sections 39.262(h) and (i).

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.253. ALLOCATION OF STRANDED COSTS. (a) Any capital costs incurred by an electric utility to improve air quality under Section 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:

(1) 50 percent 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

(2) 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 accordance with Subsections (c)-(i).

(c) The allocation to the residential class shall be determined by allocating to all customer classes 50 percent 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.

(d) After the allocation to the residential class required by Subsection (c) 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 percent of the amount allocated to that class.

(e) After the allocation to the residential class required by Subsection (c) and the allocation to the nonfirm industrial class required by Subsection (d) 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.

(f) 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.

(g) The energy consumption of the customer classes used in Subsections (a)(2) and (c) shall be based on the relevant class characteristics as of May 1, 1999, adjusted for normal weather conditions.

(h) For purposes of this section, "stranded costs" includes regulatory assets.

(i) Except as provided by Section 39.262(k), no customer or customer class may avoid the obligation to pay the amount of stranded costs allocated to that customer class.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.254. USE OF REVENUES FOR UTILITIES WITH STRANDED COSTS. This subchapter provides a number of tools to an electric utility to mitigate stranded costs. Each electric utility that was reported by the commission to have positive "excess costs over market" (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," must use these tools to reduce the net book value of, otherwise referred to as "accelerate" the cost recovery of, its stranded costs each year. Any positive difference under the report required by Section 39.257(b) shall be applied to the net book value of generation assets.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.255. USE OF REVENUES FOR UTILITIES WITH NO STRANDED COSTS. (a) An electric utility that does not have stranded costs described by Section 39.254 shall be permitted to use any positive difference under the report required by Section 39.257(b) on capital expenditures to improve or expand transmission or distribution facilities, or on capital expenditures to improve air quality, as approved by the commission. Any such capital expenditures shall be made in the calendar year immediately following the year for which the report required by Section 39.257 is calculated. The capital expenditures shall be reflected in any future proceeding under this chapter to set transmission or distribution rates as a reduction to the utility's transmission and distribution invested capital, as approved by the commission.

(b) To the extent that positive differences under the report required by Section 39.257(b) are not used for capital expenditures, the amounts shall be flowed back to the electric utility's Texas jurisdictional customers through the power cost recovery factor.

(c) This section applies only to the use of positive differences under the report required by Section 39.257(b) for each year during the freeze period.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.256. OPTION TO REDIRECT DEPRECIATION. (a) For the calendar years of 1998, 1999, 2000, and 2001, an electric utility described by Section 39.254 may redirect all or a part of the depreciation expense relating to transmission and distribution assets to its net generation plant assets.

(b) The electric utility shall report a decision under Subsection (a) to the commission and any other applicable regulatory authority.

(c) Any adjustments made to the book value of transmission and distribution assets or the creation of any related regulatory assets resulting from the redirection under this section shall be accepted and applied by the commission for establishing net invested capital and transmission and distribution rates for retail customers in all future proceedings.

(d) Notwithstanding Subsection (c), the design of post-freeze-period retail rates may not:

(1) shift the allocation of responsibility for stranded costs;

(2) include the adjusted costs in wholesale

transmission and distribution rates; or

(3) apply the adjustments for the purpose of establishing net invested capital and transmission and distribution rates for wholesale customers.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.257. ANNUAL REPORT. (a) Beginning with the 1999 calendar year, each electric utility shall file a report with the commission not later than 90 days after the end of each year during the freeze period under a schedule and a format determined by the commission.

(b) The report shall identify any positive difference between annual revenues, reduced by the amount of annual revenues under Sections 36.203 and 36.205, the revenues received under the interutility billing process as adopted by the commission to implement Sections 35.004, 35.006, and 35.007, revenues associated with transition charges as defined by Section 39.302, and annual costs.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.258. ANNUAL REPORT: DETERMINATION OF ANNUAL COSTS. For the purposes of determining the annual costs in each annual report, the following amounts shall be used:

(1) the lesser of:

(A) the utility's Texas jurisdictional operation and maintenance expense reflected in each utility's Federal Energy Regulatory Commission Form 1 of the report year, plus factoring expenses not included in operation and maintenance, adjusted for:

(i) costs under Sections 36.062, 36.203, and 36.205; and

(ii) revenues recorded under the interutility billing process adopted by the commission to implement Sections 35.004, 35.006, and 35.007; or

(B) the Texas jurisdictional operation and maintenance expense reflected in each utility's 1996 Federal Energy Regulatory Commission Form 1, plus factoring expenses not included in operation and maintenance, adjusted for:

(i) costs under Sections 36.062, 36.203, and 36.205, and not indexed for inflation;

(ii) any difference between the annual revenues and the expenses recorded under the interutility billing process adopted by the commission to implement Sections 35.004, 35.006, and 35.007; and

(iii) the annual percentage change in the average number of utility customers;

(2) the amount of nuclear decommissioning expense approved in the electric utility's last rate proceeding before the commission, as may be required to be adjusted to comply with applicable federal regulatory requirements;

(3) the depreciation rates approved in the electric utility's last rate proceeding before the commission;

(4) the amortization expense approved in the electric utility's last rate proceeding before the commission or in any other proceeding in which deferred costs and the amortization of those costs are established, except that if the items are fully amortized during the freeze period, the expense shall be adjusted accordingly;

(5) taxes and fees, including municipal franchise fees to the extent not included in Subdivision (1), other than federal income taxes, and assessments incurred that year;

(6) federal income tax expense, computed according to the stand-alone methodology and using the actual capital structure and actual cost of debt as of December 31 of the report year;

(7) return on invested capital, computed by multiplying invested capital as of December 31 of the report year, determined as provided by Section 39.259, by the cost of capital approved in the electric utility's most recent rate proceeding before the commission in which the cost of capital was specifically adopted, or, in the case of a range, the midpoint of the range, if the final rate order for the proceeding was issued on or after January 1, 1992, or if such an order does not exist, a cost of capital of 9.6 percent shall be used; and

(8) the amount resulting from any operation and maintenance expense savings tracker from a merger of two utilities

and contained in a settlement agreement approved by the commission before January 1, 1999.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.259. ANNUAL REPORT: DETERMINATION OF INVESTED CAPITAL. (a) For the purposes of determining invested capital in each annual report, the net plant in service, regulatory assets, and deferred federal income taxes shall be updated each year, and generation-related invested capital shall be reduced by the amount of securitization under Sections 39.201(i) and 39.262(c) to the extent otherwise included in invested capital.

(b) Capital additions to a plant in an amount less than 1-1/2 percent of the electric utility's net plant in service on December 31, 1998, less plant items previously excluded by the commission, for each of the years 1999 through 2001 are presumed prudent.

(c) All other items in invested capital shall be as approved in the electric utility's last rate proceeding before the commission.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.260. USE OF GENERALLY ACCEPTED ACCOUNTING PRINCIPLES. (a) The definition and identification of invested capital and other terms used in this subchapter and Subchapter G that affect the net book value of generation assets and the treatment of transactions performed under Section 35.035 and other transactions authorized by this title or approved by the regulatory authority that affect the net book value of generation assets during the freeze period shall be treated in accordance with generally accepted accounting principles as modified by regulatory accounting rules generally applicable to utilities.

(b) The principles and criteria described by Subsection (a), including the criteria for applicability of Statement of Financial Accounting Standards No. 71 ("Accounting for the Effects of Certain Types of Regulation"), shall be applied for purposes of this subchapter as they existed on January 1, 1999.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.261. REVIEW OF ANNUAL REPORT. (a) The annual report filed under this subchapter is a public document and shall be reviewed by the staff of the commission and the office. Both staffs may review work papers and supporting documents and engage in discussions with the utility about the data underlying the reports.

(b) The staff of the commission and the office shall communicate in writing to an electric utility not later than the 180th day after the date the report is filed if they have any disagreements with the data or computations.

(c) The commission shall finalize and resolve any disagreements related to the annual report, consistent with the requirements of Section 39.258, as follows:

(1) for each calendar year, the commission shall finalize the annual report before establishing the competition transition charge under Section 39.201; and

(2) for each calendar year, the commission shall finalize the annual report and reflect the result as part of the true-up proceeding under Section 39.262.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.262. TRUE-UP PROCEEDING. (a) An electric utility, together with its affiliated retail electric provider and its affiliated transmission and distribution utility, may not be permitted to overrecover stranded costs through the procedures established by this section or through the application of the measures provided by the other sections of this chapter.

(b) After the freeze period, an electric utility located in a power region that is not certified under Section 39.152 shall continue to file annual reports under Sections 39.257, 39.258, and 39.259 as if the freeze period remained in effect, until the time the power region qualifies as certified under Section 39.152. In addition, the commission staff and the office shall continue to review the annual reports as provided by Section 39.261.

(c) After January 10, 2004, at a schedule and under procedures to be determined by the commission, each transmission and distribution utility, its affiliated retail electric provider, and its affiliated power generation company shall jointly file to finalize stranded costs under Subsections (h) and (i) and reconcile those costs with the estimated stranded costs used to develop the competition transition charge in the proceeding held under Section 39.201. Any resulting difference shall be applied to the nonbypassable delivery rates of the transmission and distribution utility, except that at the utility's option, any or all of the amounts recovered under this section may be securitized under Subchapter G.

(d) The affiliated power generation company shall reconcile, and either credit or bill to the transmission and distribution utility, the net sum of:

(1) the former electric utility's final fuel balance determined under Section 39.202(c); and

(2) any difference between the price of power obtained through the capacity auctions under Sections 39.153 and 39.156 and the power cost projections that were employed for the same time period in the ECOM model to estimate stranded costs in the proceeding under Section 39.201.

(e) To the extent that the price to beat exceeded the market price of electricity, the affiliated retail electric provider shall reconcile and credit to the affiliated transmission and distribution utility any positive difference between the price to beat established under Section 39.202, reduced by the nonbypassable delivery charge established under Section 39.201, and the prevailing market price of electricity during the same time period. A reconciliation for the applicable customer class is not required under this subsection for an affiliated retail electric provider that satisfies the requirements of Section 39.202(e)(1) or (2) before the expiration of two years from the introduction of customer choice. If a reconciliation is required, in no event shall the amount credited exceed an amount equal to the number of residential or small commercial customers served by the affiliated transmission and distribution utility that are buying electricity from the affiliated retail electric provider at the price to beat on the second anniversary of the beginning of competition, minus the number of new customers obtained outside the service area, multiplied by $150.

(f) To the extent that any amount of regulatory assets included in a transition charge or competition transition charge 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 whether such amounts were appropriately calculated and constituted reasonable and necessary costs pursuant to Subchapter B, Chapter 36. If the commission finds that the amount of regulatory assets specified in Section 39.302(5) is subject to modification, a credit or other rate adjustment shall be made to the transmission and distribution utility's nonbypassable delivery rates; provided, however, that no adjustment may be made to a transition charge established under Subchapter G.

(g) Based on the credits or bills received from its affiliates under Subsections (d), (e), and (f), the transmission and distribution utility shall make necessary adjustments to the nonbypassable delivery rates it charges to retail electric providers. If the commission determines that the nonbypassable delivery rates are not sufficient, the commission may extend the original collection period for the charge or, if necessary, increase the charge. Alternatively, if the commission determines that the nonbypassable delivery rates are larger than are needed to recover the transmission and distribution utility's costs, the commission shall correspondingly reduce:

(1) the competition transition charge, to the extent it has not been securitized;

(2) the depreciation expense that has been redirected under Section 39.256;

(3) the transmission and distribution utility's rates; or

(4) a combination of the elements in Subdivisions (1)-(3).

(h) Except as provided in Subsection (i), for the purpose of finalizing the stranded cost estimate used to establish the competition transition charge under Section 39.201, the affiliated power generation company shall quantify its stranded costs using one or more of the following methods:

(1) Sale of Assets. If, at any time after December 31, 1999, an electric utility or its affiliated power generation company has sold some or all of its generation assets, which sale shall include all generating assets associated with each generating plant that is sold, in a bona fide third-party transaction under a competitive offering, the total net value realized from the sale establishes the market value of the generation assets sold. If not all assets are sold, the market value of the remaining generation assets shall be established by one or more of the other methods in this section.

(2) Stock Valuation Method. If, at any time after December 31, 1999, an electric utility or its affiliated power generation company has transferred some or all of its generation assets, including, at the election of the electric utility or power generation company, any fuel and fuel transportation contracts related to those assets, to one or more separate affiliated or nonaffiliated corporations, not less than 51 percent 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 required under Subsection (c) establishes the market value of the common stock equity in each transferee corporation. The book value of each transferee corporation's debt and preferred stock securities shall be added to the market value of its assets. The market value of each transferee corporation's assets shall be reduced by the corresponding net book value of the assets acquired by each transferee corporation from any entity other than the affiliated electric utility or power generation company. The resulting market value of the assets establishes the market value of the generation assets transferred by the electric utility or power generation company to each separate corporation. If not all assets are disposed of in this manner, the market value of the remaining assets shall be established by one or more of the other methods in this section.

(3) Partial Stock Valuation Method. If, at any time after December 31, 1999, an electric utility or its affiliated power generation company has transferred some or all of its generation assets, including, at the election of the electric utility or power generation company, any fuel and fuel transportation contracts related to those assets, to one or more separate affiliated or nonaffiliated corporations, at least 19 percent, but less than 51 percent, 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 required under Subsection (c) shall be presumed to establish the market value of the common stock equity in each transferee corporation. 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 percentage of common stock sold is fairly representative of the total common stock equity or whether a control premium exists for the retained interest. The valuation panel must consist of financial experts, chosen from proposals submitted in response to commission requests, from the top 10 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 publications "Securities Data" or "Institutional Investor." 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 increase the market value by a control premium greater than 10 percent. The costs and expenses of the panel, as approved by the commission, shall be paid by each transferee corporation. The determination of the commission based on the finding of the panel conclusively establishes the value of the common stock of each

transferee corporation. The book value of each transferee corporation's debt and preferred stock securities shall be added to the market value of its assets. The market value of each transferee corporation's assets shall be reduced by the corresponding net book value of the assets acquired by each transferee corporation from any entity other than the affiliated electric utility or power generation company. The resulting market value of the assets establishes the market value of the generation assets transferred by the electric utility or power generation company to each separate corporation.

(4) Exchange of Assets. If, at any time after December 31, 1999, an electric utility or its affiliated power generation company has transferred 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 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. 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 subdivision. 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 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.

(i) Unless an electric utility or its affiliated power generation company combines all of its remaining generation assets into one or more transferee corporations as described in Subsections (h)(2) and (3), the electric utility shall quantify its stranded costs for nuclear assets using the ECOM method. 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." At the time of the proceeding under this section, the ECOM model shall be rerun 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. Natural gas price projections used in the model must be market-based natural gas forward prices, where available. 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. Capital additions shall be benchmarked using the limitation in Section 39.259(b).

(j) The commission shall issue a final order not later than the 150th day after the date of the filing under this section by the transmission and distribution utility, its affiliated retail electric provider, and its affiliated power generation company, and the resulting order shall be subject to judicial review under Chapter 2001, Government Code.

(k) Notwithstanding Section 39.252, to the extent that a customer's actual load has been lawfully served by a fully operational qualifying facility before September 1, 2001, or by an on-site power production facility with a rated capacity of 10 megawatts or less, any charge for recovery of stranded costs under this section or Subchapter G assessed on that customer after the facility becomes fully operational shall be included only in those tariffs or charges associated with the services actually provided by the transmission and distribution utility, if any, to the customer after the facility became fully operational and may not include any costs associated with the service provided to the customer by the electric utility or its affiliated transmission and distribution utility under their tariffs before the operation of that qualifying facility. To qualify under this subsection, a qualifying facility must have made substantially complete filings on or before December 31, 1999, for all necessary site-specific environmental permits under the rules of the Texas Natural Resource Conservation Commission in effect at the time of filing.

(l) To protect retail customers in this state, and ensure the appropriateness of the nonbypassable rates of electric utilities and transmission and distribution utilities, notwithstanding any other provision of this title, an electric utility or transmission and distribution utility must report to and obtain approval of the commission before closing any transaction in which:

(1) the electric utility or transmission and distribution utility will be merged or consolidated with another electric utility or transmission and distribution utility;

(2) at least 50 percent of the stock of the electric utility or transmission and distribution utility will be transferred or sold; or

(3) a controlling interest or operational control of the electric utility or transmission and distribution utility will be transferred.

(m) The commission shall approve a transaction under Subsection (l) if the commission finds that the transaction is in the public interest. In making its determination, the commission shall consider whether the transaction will adversely affect the reliability of service, availability of service, or cost of service of the electric utility or transmission and distribution utility. The commission shall make the determination concerning a transaction under this subsection not later than the 180th day after the date the commission receives the relevant report. The commission may extend the deadline provided by this subsection for not more than 60 days if the commission determines the extension is needed to evaluate additional information, to consider actions taken by other jurisdictions concerning the transaction, to provide for administrative efficiency, or for other good cause. If the commission has not made a determination before the expiration of the deadline provided by or extended under this subsection, the transaction is considered approved.

(n) Subsections (l) and (m) do not apply to a transaction described by Subsection (l) for which a definitive agreement was executed before April 1, 2007, if an electric utility or transmission and distribution utility or a person seeking to acquire or merge with an electric utility or transmission and distribution utility made a filing for review of the transaction under Section 14.101 before May 1, 2007, and the resulting proceeding was not withdrawn.

(o) If an electric utility or transmission and distribution utility or a person seeking to acquire or merge with an electric utility or transmission and distribution utility files with the commission a stipulation, representation, or commitment in advance of or as part of a filing under Subsection (l) or under Section 14.101, the commission may enforce the stipulation, representation, or commitment to the extent that the stipulation, representation, or commitment is consistent with the standards provided by this section and Section 14.101. The commission may reasonably interpret and enforce conditions adopted under this section.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2007, 80th Leg., R.S., Ch. 1186 (H.B. 624), Sec. 1, eff. June 15, 2007.

Acts 2017, 85th Leg., R.S., Ch. 200 (S.B. 735), Sec. 3, eff. May 27, 2017.

Sec. 39.263. STRANDED COST RECOVERY OF ENVIRONMENTAL CLEANUP COSTS. (a) Subject to Subsection (c), capital costs incurred by an electric utility to improve air quality before January 1, 2002, are eligible for inclusion as net invested capital under Section 39.259, notwithstanding the limitations imposed under Sections 39.259(b) and (c).

(b) Subject to Subsection (c), capital costs incurred by an electric utility or an affiliated power generation company to improve air quality after January 1, 2002, and before May 1, 2003, are eligible for inclusion in the determination of invested capital in the true-up proceeding under Section 39.262.

(c) Reasonable costs incurred under Subsections (a) and (b) shall be included as invested capital and considered in an electric utility's stranded cost determination only to the extent that:

(1) the cost is applied to offset or reduce the emission of airborne contaminants from an electric generating facility, where:

(A) the reduction or offset is determined by the Texas Natural Resource Conservation Commission to be an essential component in achieving compliance with a national ambient air quality standard; or

(B) the reduction or offset is necessary in order for an unpermitted electric generating facility to obtain a permit in the manner provided by Section 39.264;

(2) the retrofit decision is determined to be the most cost-effective after consideration of alternative measures, including the retirement of the generating facility; and

(3) the amount and location of resulting emission reductions is consistent with the air quality goals and policies of the Texas Natural Resource Conservation Commission.

(d) If the retirement of a generating facility is the most cost-effective alternative, taking into account the cost of replacement generating capacity, the net book value, including retirement costs and offsetting salvage value, of the affected facility shall be included in the electric utility's stranded cost determination, notwithstanding Section 39.259(c).

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.264. EMISSIONS REDUCTIONS OF "GRANDFATHERED FACILITIES". (a) In this section:

(1) "Conservation commission" means the Texas Natural Resource Conservation Commission.

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

(b) This section applies only to an electric generating facility existing on January 1, 1999, that is not subject to the requirement to obtain a permit under Section 382.0518(g), Health and Safety Code.

(c) It is the intent of the legislature that, for the 12-month period beginning on May 1, 2003, and for each 12-month period after the end of that period, total annual emissions of nitrogen oxides from facilities subject to this section may not exceed levels equal to 50 percent of the total emissions of that pollutant during 1997, as reported to the conservation commission, and total annual emissions of sulphur dioxides from coal-fired facilities subject to this section may not exceed levels equal to 75 percent of the total emissions of that pollutant during 1997, as reported to the conservation commission. The limitations prescribed by this subsection may be met through an emissions allocation and allowance transfer system described by this section.

(d) A municipal corporation, electric cooperative, or river authority may exclude any electric generating facilities of 25 megawatts or less from the requirements prescribed by this section. Not later than January 1, 2000, a municipal corporation, electric cooperative, or river authority must inform the conservation commission of its intent to exclude those facilities.

(e) The owner or operator of an electric generating facility shall apply to the conservation commission for a permit for the emission of air contaminants on or before September 1, 2000. A permit issued by the conservation commission under this section shall require the facility to achieve emissions reductions or trading emissions allowances as provided by this section. If the facility uses coal as a fuel, the permit must also be conditioned on the facility's emissions meeting opacity limitations provided by conservation commission rules. Notwithstanding Section 382.0518(g), Health and Safety Code, a facility that does not obtain a permit as required by this subsection may not operate after May 1, 2003, unless the conservation commission finds good cause for an extension.

(f) The conservation commission shall develop rules for the permitting of electric generating facilities. The rules adopted under this subsection shall provide, by region, for the allocation of emissions allowances of sulphur dioxides and nitrogen oxides among electric generating facilities and for facilities to trade emissions allowances for those contaminants.

(g) The conservation commission by rule shall establish an East Texas Region, a West Texas Region, and an El Paso Region for allocation of air contaminants under the permitting program under Subsection (f). The East Texas Region must contain all counties traversed by or east of Interstate Highway 35 or Interstate Highway 37, including Bosque, Coryell, Hood, Parker, Somervell, and Wise counties. The West Texas Region includes all of the state not contained in the East Texas Region or the El Paso Region. The El Paso Region includes El Paso County.

(h) Not later than January 1, 2000, the conservation commission shall allocate to each electric generating facility in each region a number of annual emissions allowances, with each allowance equal to one ton of sulphur dioxides or of nitrogen oxides emitted in a year, that permit emissions of the contaminants from the facility in that year. The conservation commission must allocate to each facility a number of emissions allowances equal to an emissions rate measured in pounds per million British thermal units divided by 2,000 and multiplied by the facility's total heat input in terms of million British thermal units during 1997. For the East Texas Region, the emissions rate shall be 0.14 pounds per million British thermal units for nitrogen oxides and 1.38 pounds per million British thermal units for sulphur dioxides. For the West Texas and El Paso regions, the emissions rate shall be 0.195 pounds per million British thermal units for nitrogen oxides. Allowances for sulphur dioxides may only be allocated among coal-fired facilities.

(i) A person, municipal corporation, electric cooperative, or river authority that owns and operates an electric generating facility not covered by this section may elect to designate that facility to become subject to the requirements of this section and to receive emissions allowances for the purpose of complying with the emissions limitations prescribed by Subsection (c). The conservation commission shall adopt rules governing this election that:

(1) require an owner or operator of an electric generating facility to designate to the conservation commission in

its permit application under Subsection (e) any facilities that will become subject to this section;

(2) require the conservation commission, notwithstanding the allocation mechanism provided by Subsection (h), to allocate additional allowances to facilities governed by this subsection in an amount equal to each facility's actual emissions in tons in 1997;

(3) provide that any unit designated under this subsection may not transfer or bank allowances conserved as a result of reduced utilization or shutdown, except that the allowances may be transferred or carried forward for use in subsequent years to the extent that the reduced utilization or shutdown results from the replacement of thermal energy from the unit designated under this subsection with thermal energy generated by any other unit; and

(4) provide that emissions reductions from electing facilities designated in this subsection may only be used to satisfy the emissions reductions for grandfathered facilities defined in Subsection (c) to the extent that reductions used to satisfy the limitations in Subsection (c) are beyond the requirements of any other state or federal standard, or both.

(j) The conservation commission by rule shall permit a facility to trade emissions allocations with other electric generating facilities only in the same region.

(k) The conservation commission by rule shall provide methods for the conservation commission to determine whether a facility complies with the permit issued under this section. The rules must provide for:

(1) monitoring and reporting actual emissions of sulphur dioxides and nitrogen oxides from each facility;

(2) provisions for saving unused allowances for use in later years; and

(3) a system for tracking traded allowances.

(l) A facility may not trade an unused allowance for a contaminant for use as a credit for another contaminant.

(m) A person possessing market power shall not withhold emissions allowances from the market in a manner that is unreasonably discriminatory or tends to unreasonably restrict, impair, or reduce the level of competition.

(n) The conservation commission shall penalize a facility that emits an air contaminant that exceeds the facility's allowances for that contaminant by:

(1) enforcing an administrative penalty, in an amount determined by conservation commission rules, for each ton of air contaminant emissions by which the facility exceeds its allocated emissions allowances; and

(2) reducing the facility's emissions allowances for the next year by an amount of emissions equal to the excessive emissions in the year the facility emitted the excessive air contaminants.

(o) The conservation commission may penalize a facility that emits an air contaminant that exceeds the facility's allowances for that contaminant by:

(1) ordering the facility to cease operations; or

(2) taking other enforcement action provided by conservation commission rules.

(p) The conservation commission by rule shall provide for a facility in the El Paso Region to meet emissions allowances by using credits from emissions reductions achieved in Ciudad Juarez, United Mexican States.

(q) If the conservation commission or the United States Environmental Protection Agency determines that reductions in nitrogen oxides emissions in the El Paso Region otherwise required by this section would result in increased ambient ozone levels in El Paso County, facilities in the El Paso Region are exempt from the nitrogen oxides reduction requirements.

(r) An applicant for a permit under Subsection (e) shall publish notice of intent to obtain the permit in accordance with Section 382.056, Health and Safety Code. The conservation commission shall provide an opportunity for a public hearing and the submission of public comment and send notice of a decision on an application for a permit under Subsection (e) in the same manner as provided by Sections 382.0561 and 382.0562, Health and Safety Code. The conservation commission shall review and renew a permit issued under this section in accordance with Section 382.055, Health and Safety Code.

(s) This section does not limit the authority of the conservation commission to require further reductions of nitrogen oxides, sulphur dioxides, or any other pollutant from generating facilities subject to this section or Section 39.263.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.265. RIGHTS NOT AFFECTED. This chapter is not intended to alter any rights of utilities to recover stranded costs from wholesale customers.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

SUBCHAPTER G. SECURITIZATION

Sec. 39.301. PURPOSE. The purpose of this subchapter is to enable utilities to use securitization financing to recover regulatory assets, all other amounts determined under Section 39.262, and any amounts being recovered under a competition transition charge determined as a result of the proceedings under Sections 39.201 and 39.262. This type of debt will lower the carrying costs of the assets relative to the costs that would be incurred using conventional utility financing methods. The proceeds of the transition bonds shall be used solely for the purposes of reducing the amount of recoverable regulatory assets and other amounts, as determined by the commission in accordance with this chapter, through the refinancing or retirement of utility debt or equity. The commission shall ensure that securitization provides tangible and quantifiable benefits to ratepayers, greater than would have been achieved absent the issuance of transition bonds. The commission shall ensure that the structuring and pricing of the transition bonds result in the lowest transition bond charges consistent with market conditions and the terms of the financing order. The amount securitized may not exceed the present value of the revenue requirement over the life of the proposed transition bond associated with the regulatory assets or other amounts sought to be securitized. The present value calculation shall use a discount rate equal to the proposed interest rate on the transition bonds.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2007, 80th Leg., R.S., Ch. 1186 (H.B. 624), Sec. 2, eff. June 15, 2007.

Sec. 39.302. DEFINITIONS. In this subchapter:

(1) "Assignee" means any individual, corporation, or other legally recognized entity to which an interest in transition property is transferred, other than as security, including any assignee of that party.

(2) "Financing order" means an order of the commission adopted under Section 39.201 or 39.262 approving the issuance of transition bonds and the creation of transition charges for the recovery of qualified costs.

(3) "Financing party" means a holder of transition bonds, including trustees, collateral agents, and other persons acting for the benefit of the holder.

(4) "Qualified costs" means 100 percent of an electric utility's regulatory assets and 75 percent of its recoverable costs determined by the commission under Section 39.201 and any remaining amounts determined under Section 39.262 together with the costs of issuing, supporting, and servicing transition bonds and any costs of retiring and refunding the electric utility's existing debt and equity securities in connection with the issuance of transition bonds. The term includes the costs to the commission of acquiring professional services for the purpose of evaluating proposed transactions under Section 39.201 and this subchapter.

(5) "Regulatory assets" means 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.

(6) "Transition bonds" means 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 by or payable from transition property. If certificates of participation, beneficial interest, or ownership are issued, references in this subchapter to principal, interest, or premium shall refer to comparable amounts under those certificates.

(7) "Transition charges" means 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 the financing order.

(8) "Transition property" means the property described in Section 39.304.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2007, 80th Leg., R.S., Ch. 1186 (H.B. 624), Sec. 3, eff. June 15, 2007.

Sec. 39.303. FINANCING ORDERS; TERMS. (a) The commission shall adopt a financing order, on application of a utility to recover the utility's regulatory assets and other amounts determined under Section 39.201 or 39.262, on making a finding that the total amount of revenues to be collected under the financing order is less than the revenue requirement that would be recovered over the remaining life of the regulatory assets or other amounts using conventional financing methods and that the financing order is consistent with the standards in Section 39.301.

(b) The financing order shall detail the amount of regulatory assets and other amounts to be recovered and the period over which the nonbypassable transition charges shall be recovered, which period may not exceed 15 years. If an amount determined under Section 39.262 is subject to judicial review at the time of the securitization proceeding, the financing order shall include an adjustment mechanism requiring the utility to adjust its rates, other than transition charges, or provide credits, other than credits to transition charges, in a manner that would refund over the remaining life of the transition bonds any overpayments resulting from securitization of amounts in excess of the amount resulting from a final determination after completion of all appellate reviews. The adjustment mechanism may not affect the stream of revenue available to service the transition bonds. An adjustment may not be made under this subsection until all appellate reviews, including, if applicable, appellate reviews following a commission decision on remand of its original orders, have been completed.

(c) Transition charges shall be collected and allocated among customers in the same manner as competition transition charges under Section 39.201.

(d) A financing order shall become effective in accordance with its terms, and the financing order, together with the transition charges authorized in the order, shall thereafter be irrevocable and not subject to reduction, impairment, or adjustment by further action of the commission, except as permitted by Section 39.307.

(e) The commission shall issue a financing order under Subsections (a) and (g) not later than 90 days after the utility files its request for the financing order.

(f) A financing order is not subject to rehearing by the commission. A financing order may be reviewed by appeal only to a Travis County district court by a party to the proceeding filed within 15 days after the financing order is signed by the commission. The judgment of the district court may be reviewed only by direct appeal to the Supreme Court of Texas filed within 15 days after entry of judgment. All appeals shall be heard and determined by the district court and the Supreme Court of Texas as expeditiously as possible with lawful precedence over other matters. Review on appeal shall be based solely on the record before the commission and briefs to the court and shall be limited to whether the financing order conforms to the constitution and laws of this state and the United States and is within the authority of the commission under this chapter.

(g) At the request of an electric utility, the commission may adopt a financing order providing for retiring and refunding transition bonds on making a finding that the future transition charges required to service the new transition bonds, including transaction costs, will be less than the future transition charges required to service the transition bonds being refunded. On the retirement of the refunded transition bonds, the commission shall adjust the related transition charges accordingly.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2007, 80th Leg., R.S., Ch. 1186 (H.B. 624), Sec. 4, eff. June 15, 2007.

Sec. 39.304. PROPERTY RIGHTS. (a) The rights and interests of an electric utility or successor under a financing order, including the right to impose, collect, and receive transition charges authorized in the order, shall be only contract rights until they are first transferred to an assignee or pledged in connection with the issuance of transition bonds, at which time they will become "transition property."

(b) Transition property shall constitute a present property right for purposes of contracts concerning the sale or pledge of property, even though the imposition and collection of transition charges depends on further acts of the utility or others that have not yet occurred. The financing order shall remain in effect and the property shall continue to exist for the same period as the pledge of the state described in Section 39.310.

(c) All revenues and collections resulting from transition charges shall constitute proceeds only of the transition property arising from the financing order.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.305. NO SETOFF. The interest of an assignee or pledgee in transition property and in the revenues and collections arising from that property are not subject to setoff, counterclaim, surcharge, or defense by the electric utility or any other person or in connection with the bankruptcy of the electric utility or any other entity. A financing order shall remain in effect and unabated notwithstanding the bankruptcy of the electric utility, its successors, or assignees.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.306. NO BYPASS. A financing order shall include terms ensuring that the imposition and collection of transition charges authorized in the order shall be nonbypassable.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.307. TRUE-UP. A 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.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.308. TRUE SALE. An agreement by an electric utility or assignee to transfer transition property that expressly states that the transfer is a sale or other absolute transfer signifies that the transaction is a true sale and is not a secured transaction and that title, legal and equitable, has passed to the entity to which the transition property is transferred. This true sale shall apply regardless of whether the purchaser has any recourse against the seller, or any other term of the parties' agreement, including the seller's retention of an equity interest in the transition property, the fact that the electric utility acts as the collector of transition charges relating to the transition property, or the treatment of the transfer as a financing for tax, financial reporting, or other purposes.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.309. SECURITY INTERESTS; ASSIGNMENT; COMMINGLING; DEFAULT. (a) Transition property does not constitute an account or general intangible under Section 9.106, Business & Commerce Code.

The creation, granting, perfection, and enforcement of liens and security interests in transition property are governed by this section and not by the Business & Commerce Code.

(b) A valid and enforceable lien and security interest in transition property may be created only by a financing order and the execution and delivery of a security agreement with a financing party in connection with the issuance of transition bonds. The lien and security interest shall attach automatically from the time that value is received for the bonds and, on perfection through the filing of notice with the secretary of state in accordance with the rules prescribed under Subsection (d), shall be a continuously perfected lien and security interest in the transition property and all proceeds of the property, whether accrued or not, shall have priority in the order of filing and take precedence over any subsequent judicial or other lien creditor. If notice is filed within 10 days after value is received for the transition bonds, the security interest shall be perfected retroactive to the date value was received, otherwise, the security interest shall be perfected as of the date of filing.

(c) Transfer of an interest in transition property to an assignee shall be perfected against all third parties, including subsequent judicial or other lien creditors, when the financing order becomes effective, transfer documents have been delivered to the assignee, and a notice of that transfer has been filed in accordance with the rules prescribed under Subsection (d); provided, however, that if notice of the transfer has not been filed in accordance with this subsection within 10 days after the delivery of transfer documentation, the transfer of the interest is not perfected against third parties until the notice is filed.

(d) The secretary of state shall implement this section by establishing and maintaining a separate system of records for the filing of notices under this section and prescribing the rules for those filings based on Chapter 9, Business & Commerce Code, adapted to this subchapter and using the terms defined in this subchapter.

(e) The priority of a lien and security interest perfected under this section is not impaired by any later modification of the financing order under Section 39.307 or by the commingling of funds arising from transition charges with other funds, and any other security interest that may apply to those funds shall be terminated when they are transferred to a segregated account for the assignee or a financing party. If transition property has been transferred to an assignee, any proceeds of that property shall be held in trust for the assignee.

(f) If a default or termination occurs under the transition bonds, the financing parties or their representatives may foreclose on or otherwise enforce their lien and security interest in any transition property as if they were secured parties under Chapter 9, Business & Commerce Code, and the commission may order that amounts arising from transition charges be transferred to a separate account for the financing parties' benefit, to which their lien and security interest shall apply. On application by or on behalf of the financing parties, a district court of Travis County shall order the sequestration and payment to them of revenues arising from the transition charges.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.310. PLEDGE OF STATE. Transition bonds are not a debt or obligation of the state and are not a charge on its full faith and credit or taxing power. The state pledges, however, for the benefit and protection of financing parties and the electric utility, that it will not take or permit any action that would impair the value of transition property, or, except as permitted by Section 39.307, reduce, alter, or impair the transition charges to be imposed, collected, and remitted to financing parties, until the principal, interest and premium, and any other charges incurred and contracts to be performed in connection with the related transition bonds have been paid and performed in full. Any party issuing transition bonds is authorized to include this pledge in any documentation relating to those bonds.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.311. TAX EXEMPTION. Transactions involving the transfer and ownership of transition property and the receipt of transition charges are exempt from state and local income, sales, franchise, gross receipts, and other taxes or similar charges.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.312. NOT PUBLIC UTILITY. An assignee or financing party may not be considered to be a public utility or person providing electric service solely by virtue of the transactions described in this subchapter.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.313. SEVERABILITY. Effective on the date the first utility transition bonds are issued under this subchapter, if any provision in this title or portion of this title is held to be invalid or is invalidated, superseded, replaced, repealed, or expires for any reason, that occurrence does not affect the validity or continuation of this subchapter, Section 39.201, 39.251, 39.252, or 39.262, or any part of those provisions, or any other provision of this title that is relevant to the issuance, administration, payment, retirement, or refunding of transition bonds or to any actions of the electric utility, its successors, an assignee, a collection agent, or a financing party, which shall remain in full force and effect.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

SUBCHAPTER H. CERTIFICATION AND REGISTRATION; PENALTIES

Sec. 39.351. REGISTRATION OF POWER GENERATION COMPANIES.

(a) A person may not generate electricity unless:

(1) the person is registered with the commission as a power generation company in accordance with this section; or

(2) the electricity is generated as part of a registered aggregate distributed energy resource under Section 39.3515.

(a-1) A person may register as a power generation company by filing the following information with the commission:

(1) a description of the location of any facility used to generate electricity;

(2) a description of the type of services provided;

(3) a copy of any information filed with the Federal Energy Regulatory Commission in connection with registration with that commission; and

(4) any other information required by commission rule, provided that in requiring that information the commission shall protect the competitive process in a manner that ensures the confidentiality of competitively sensitive information.

(b) A power generation company shall comply with the reliability standards adopted by an independent organization certified by the commission to ensure the reliability of the regional electrical network for a power region in which the power generation company is generating or selling electricity.

(c) The commission may establish simplified filing requirements for distributed natural gas generation facilities.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2011, 82nd Leg., R.S., Ch. 890 (S.B. 365), Sec. 4, eff. September 1, 2011.

Acts 2023, 88th Leg., R.S., Ch. 945 (S.B. 1699), Sec. 3, eff. September 1, 2023.

Sec. 39.3515. AGGREGATE DISTRIBUTED ENERGY RESOURCES. (a) A person who aggregates distributed energy resources:

(1) is not required to register as a power generation company to aggregate the resources;

(2) shall comply with rules, guidelines, and registration requirements established by the commission and by Chapter 17 and this chapter; and

(3) remains accountable for compliance with the applicable statutes and rules by a subcontractor, an agent, or any other entity compensated by the person for activities conducted on the person's behalf.

(b) The commission may establish rules and registration requirements for the aggregation of distributed energy resources.

Added by Acts 2023, 88th Leg., R.S., Ch. 945 (S.B. 1699), Sec. 4, eff. September 1, 2023.

Sec. 39.352. CERTIFICATION OF RETAIL ELECTRIC PROVIDERS. (a) After the date of customer choice, a person, including an affiliate of an electric utility, may not provide retail electric service in this state unless the person is certified by the commission as a retail electric provider, in accordance with this section.

(b) The commission shall issue a certificate to provide retail electric service to a person applying for certification who demonstrates:

(1) the financial and technical resources to provide continuous and reliable electric service to customers in the area for which the certification is sought;

(2) the managerial and technical ability to supply electricity at retail in accordance with customer contracts;

(3) the resources needed to meet the customer protection requirements of this title; and

(4) ownership or lease of an office located within this state for the purpose of providing customer service, accepting service of process, and making available in that office books and records sufficient to establish the retail electric provider's compliance with the requirements of this subchapter.

(c) A person applying for certification under this section shall comply with all applicable customer protection provisions, disclosure requirements, and marketing guidelines established by the commission and by this title.

(d) Notwithstanding Subsections (b)(1)-(3), if a retail electric provider files with the commission a signed, notarized affidavit from each retail customer with which it has contracted to provide one megawatt or more of capacity stating that the customer is satisfied that the retail electric provider meets the standards prescribed by Subsections (b)(1)-(3) and Subsection (c), the retail electric provider shall be certified for purposes of serving those customers only, so long as it demonstrates that it meets the requirements of Subsection (b)(4).

(e) A retail electric provider may apply for certification any time after September 1, 2000.

(f) The commission shall use any information required in this section in a manner that ensures the confidentiality of competitively sensitive information.

(g) If a retail electric provider serves an aggregate load in excess of 300 megawatts within this state, not less than five percent of the load in megawatt hours must consist of residential customers. This requirement applies to an affiliated retail electric provider only with respect to load served outside of the electric utility's service area, and, in relation to that load, the affiliated retail electric provider shall meet the requirements of this subsection by serving residential customers outside of the electric utility's service area. For the purpose of this subsection, the load served by retail electric providers that are under common ownership shall be combined. A retail electric provider may meet the requirements of this subsection by demonstrating on an annual basis that it serves residential load amounting to five percent of its total load or by demonstrating that another retail electric provider serves sufficient qualifying residential load on its behalf. Qualifying residential load may not include customers served by an affiliated retail electric provider in its own service area. Each retail electric provider shall file reports with the commission that are necessary to implement this subsection. This subsection applies for 36 months after retail competition begins. The commission shall adopt rules to implement this subsection.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.
Amended by:

Acts 2019, 86th Leg., R.S., Ch. 467 (H.B. 4170), Sec. 16.002, eff. September 1, 2019.

Sec. 39.353. REGISTRATION OF AGGREGATORS. (a) A person may not provide aggregation services in the state unless the person is registered with the commission as an aggregator.

(b) In this subchapter, "aggregator" means 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.

(c) A person registering under this section shall comply with all customer protection provisions, all disclosure requirements, and all marketing guidelines established by the commission and by this title.

(d) The commission shall establish terms and conditions it determines necessary to regulate the reliability and integrity of aggregators in the state by June 1, 2000.

(e) An aggregator may register any time after September 1, 2000.

(f) The commission shall have up to 60 days to process applications for registration filed by aggregators.

(g) Registration is not required of a customer that is aggregating loads from its own location or facilities.

(h) The commission shall work with the Texas Department of Economic Development to communicate information about opportunities for operation as aggregators to potential new aggregators, including small and historically underutilized businesses.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.3535. MILITARY BASES AGGREGATORS. (a) In this section, "military bases aggregator" means a person joining two or more military bases that are located in areas of the state offering customer choice under this chapter into a single purchasing unit to negotiate electricity purchases from retail electric providers.

(b) It is the policy of this state to encourage military bases located in areas of the state offering customer choice under this chapter to aggregate their facilities into a single purchasing unit as a method to reduce costs of electricity consumed by those bases. The commission shall provide assistance to a military bases aggregator regarding the evaluation of offers from retail electric providers on the request of the military bases aggregator.

(c) An aggregator registered under another section of this subchapter may provide aggregation services to military bases.

(d) A person, including a state agency, may register as a military bases aggregator to provide aggregation services exclusively to military bases located in areas of the state offering customer choice under this chapter.

(e) A person registered as a military bases aggregator under Subsection (d) is not required to comply with customer protection provisions, disclosure requirements, or marketing guidelines prescribed by this title or established by the commission while providing aggregation services exclusively to military bases.

(f) The commission shall expedite consideration of an application submitted by an applicant for registration under Subsection (d).

Added by Acts 2003, 78th Leg., ch. 149, Sec. 22, eff. May 27, 2003.

Sec. 39.354. REGISTRATION OF MUNICIPAL AGGREGATORS. (a) A municipal aggregator may not provide aggregation services in the state unless the municipal aggregator registers with the commission.

(b) In this section, "municipal aggregator" means 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 retail electric providers or aggregation by a municipality under Chapter 304, Local Government Code.

(c) A municipal aggregator may register any time after September 1, 2000.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999; Acts 2001, 77th Leg., ch. 1420, Sec. 21.002(22), eff. Sept. 1, 2001.

Sec. 39.3545. REGISTRATION OF POLITICAL SUBDIVISION AGGREGATORS. (a) A political subdivision aggregator may not provide aggregation services in the state unless the political subdivision aggregator registers with the commission.

(b) In this section, "political subdivision aggregator" means 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 retail electric providers for the facilities of the aggregated political subdivisions or aggregation by a person or political subdivision under Chapter 304, Local Government Code.

(c) A political subdivision aggregator may register any time after September 1, 2000.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999; Acts 2001, 77th Leg., ch. 1420, Sec. 21.002(23), eff. Sept. 1, 2001.

Sec. 39.355. REGISTRATION OF POWER MARKETERS. A person may not sell electric energy at wholesale as a power marketer unless the person registers with the commission pursuant to Section 35.032.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.3555. REGISTRATION OF BROKERS. (a) In this section, "brokerage services" means providing advice or procurement services to, or acting on behalf of, a retail electric customer regarding the selection of a retail electric provider, or a product or service offered by a retail electric provider.

(b) A person may not provide brokerage services, including brokerage services offered online, in this state for compensation or other consideration unless the person is registered with the commission as a broker.

(c) A retail electric provider may not register as a broker. A broker may not sell or take title to electric energy.

(d) A retail electric provider may not knowingly provide bids or offers to a person who:

(1) provides brokerage services in this state for compensation or other consideration; and

(2) has not registered as a broker with the commission.

(e) A person who registers under this section shall comply with customer protection provisions, disclosure requirements, and marketing guidelines established by the commission and by this chapter and Chapter 17.

(f) The commission shall adopt rules as necessary to implement this section.

(g) The commission shall process a person's application for registration as a broker not later than the 60th day after the date the person files the application.

Added by Acts 2019, 86th Leg., R.S., Ch. 1373 (S.B. 1497), Sec. 1, eff. September 1, 2019.

Sec. 39.356. REVOCATION OF CERTIFICATION. (a) The commission may suspend, revoke, or amend a retail electric provider's certificate for significant violations of this title or the rules adopted under this title or of any reliability standard adopted by an independent organization certified by the commission to ensure the reliability of a power region's electrical network, including the failure to observe any scheduling, operating, planning, reliability, or settlement protocols established by the independent organization. The commission may also suspend or revoke a retail electric provider's certificate if the provider no longer has the financial or technical capability to provide continuous and reliable electric service.

(b) The commission may suspend or revoke a power generation company's registration for significant violations of this title or the rules adopted under this title or of the reliability standards adopted by an independent organization certified by the commission to ensure the reliability of a power region's electrical network, including the failure to observe any scheduling, operating, planning, reliability, or settlement protocols established by the independent organization.

(c) The commission may suspend or revoke an aggregator's registration for significant violations of this title or of the rules adopted under this title.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.357. ADMINISTRATIVE PENALTY. In addition to the suspension, revocation, or amendment of a certification, the commission may impose an administrative penalty, as provided by Section 15.023, for violations described by Section 39.356.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.358. LOCAL REGISTRATION OF RETAIL ELECTRIC PROVIDER. (a) A municipality may require a retail electric provider to register with the municipality as a condition of serving residents of the municipality. The municipality may assess a reasonable administrative fee for this purpose.

(b) The municipality may suspend or revoke a retail electric provider's registration and operation in that municipality for significant violations of this chapter or the rules adopted under this chapter.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.359. BILL PAYMENT ASSISTANCE FOR BURNED VETERANS. (a) A retail electric provider may establish a bill payment assistance program for a customer who is a military veteran who a medical doctor certifies has a significantly decreased ability to regulate the individual's body temperature because of severe burns received in combat.

(b) The commission shall compile a list of programs described by Subsection (a) that are available from retail electric providers. The commission shall publish the list on the commission's Internet website and the office shall provide on the office's Internet website a link to the list.

(c) A retail electric provider shall provide to the commission information necessary to compile the list in the form, manner, and frequency the commission by rule requires.

Added by Acts 2013, 83rd Leg., R.S., Ch. 597 (S.B. 981), Sec. 2, eff. June 14, 2013.

Text of section as added by Acts 2023, 88th Leg., R.S., Ch. 464 (S.B. 2013), Sec. 5

For text of section as added by Acts 2023, 88th Leg., R.S., Ch. 463 (S.B. 1929), Sec. 1, see other Sec. 39.360.

Sec. 39.360. TRANSACTIONS WITH CERTAIN FOREIGN-OWNED COMPANIES IN CONNECTION WITH CRITICAL INFRASTRUCTURE. (a) In this section, "company" and "critical infrastructure" have the meanings assigned by Section 113.001, Business & Commerce Code, as added by Chapter 975 (S.B. 2116), Acts of the 87th Legislature, Regular Session, 2021.

(b) An independent organization certified under Section 39.151 may not register a business entity or maintain the registration of a business entity to operate in the power region for which the independent organization is certified unless the business entity attests that the entity complies with Chapter 113, Business & Commerce Code, as added by Chapter 975 (S.B. 2116), Acts of the 87th Legislature, Regular Session, 2021.

(c) An independent organization certified under Section 39.151 shall require as a condition of operating in the power region for which the independent organization is certified that a business entity report to the independent organization the purchase of any critical electric grid equipment or service from a company described by Section 113.002(a)(2), Business & Commerce Code, as added by Chapter 975 (S.B. 2116), Acts of the 87th Legislature, Regular Session, 2021.

(d) For each purchase reported by a business entity under Subsection (c), the business entity shall submit an attestation to the independent organization that the purchase will not result in access to or control of its critical electric grid equipment by a company described by Section 113.002(a)(2), Business & Commerce Code, as added by Chapter 975 (S.B. 2116), Acts of the 87th Legislature, Regular Session, 2021, excluding access specifically allowed by the business entity for product warranty and support purposes.

(e) Notwithstanding any other law, an independent organization certified under Section 39.151 may immediately suspend or terminate a company's registration or access to any of the independent organization's systems if the independent organization has a reasonable suspicion that the company meets any of the criteria described by Section 2274.0102(a)(2), Government Code, as added by Chapter 975 (S.B. 2116), Acts of the 87th Legislature, Regular Session, 2021.

(f) A contractual provision that limits or contradicts Subsection (e) is contrary to public policy and is unenforceable and void.

(g) An independent organization certified under Section 39.151 may adopt guidelines or procedures relating to the requirements in this section, including the qualification of electric grid equipment or services as critical.

(h) The commission shall adopt any rules necessary to administer this section or authorize an independent organization to carry out a duty imposed by this section.

(i) The attorney general may conduct periodic audits of the attestations required by Subsection (d) and may prioritize the audits as necessary to protect critical infrastructure.

Added by Acts 2023, 88th Leg., R.S., Ch. 464 (S.B. 2013), Sec. 5, eff. June 9, 2023.

Text of section as added by Acts 2023, 88th Leg., R.S., Ch. 463 (S.B. 1929), Sec. 1

For text of section as added by Acts 2023, 88th Leg., R.S., Ch. 464 (S.B. 2013), Sec. 5, see other Sec. 39.360.

Sec. 39.360. LARGE FLEXIBLE LOAD REGISTRATION. (a) In this section:

(1) "Virtual currency" has the meaning assigned by Section 12.001, Business & Commerce Code.

(2) "Virtual currency mining facility" means a facility that uses electronic equipment to add virtual currency transactions to a distributed ledger.

(b) The commission by rule shall require a person operating a virtual currency mining facility who enters into an agreement for retail electric service in the ERCOT power region to register the facility receiving service as a large flexible load under this section if:

(1) the facility requires a total load of more than 75 megawatts; and

(2) the facility load is interruptible.

(c) The rules must require a person described by Subsection (b) to:

(1) register the large flexible load with the commission not later than one business day after the date the agreement begins; and

(2) provide the commission with:

(A) the location of the facility; and

(B) the anticipated demand from the facility for the five-year period beginning on the date of the registration.

(d) The commission by rule shall:

(1) adopt criteria for determining whether a load is interruptible for the purposes of this section based on whether it is possible for the facility operator to choose to interrupt the load; and

(2) establish a method to ensure compliance with this section.

(e) The commission may share with an independent organization certified under Section 39.151 registration information received under this section.

Added by Acts 2023, 88th Leg., R.S., Ch. 463 (S.B. 1929), Sec. 1, eff. September 1, 2023.

SUBCHAPTER I. PROVISIONS FOR CERTAIN NON-ERCOT UTILITIES

Sec. 39.401. APPLICABILITY. This subchapter shall apply to investor-owned electric utilities operating solely outside of ERCOT having fewer than six synchronous interconnections with voltage levels above 69 kilovolts systemwide on the effective date of this subchapter. The legislature finds that circumstances exist that require that areas served by such utilities be treated as competitive development areas in which it is not in the public interest to transition to full retail customer choice at this time.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999. Amended by Acts 2001, 77th Leg., ch. 1041, Sec. 1, eff. June 15, 2001.

Sec. 39.402. REGULATION OF UTILITY AND TRANSITION TO COMPETITION. (a) Until the date on which an electric utility subject to this subchapter is authorized by the commission to implement customer choice, the rates of the utility shall be regulated under traditional cost of service regulation and the utility is subject to all applicable regulatory authority prescribed by this subtitle and Subtitle A, including Chapters 14, 32, 33, 36, and 37. Until the date on which an electric utility subject to this subchapter implements customer choice, the provisions of this chapter, other than this subchapter, Sections

39.1516 and 39.905, and the provisions relating to the duty to obtain a permit from the Texas Commission on Environmental Quality for an electric generating facility and to reduce emissions from an electric generating facility, shall not apply to that utility. That portion of any commission order entered before September 1, 2001, to comply with this subchapter shall be null and void.

(b) Until the date on which an electric utility subject to this subchapter implements customer choice, Section 33.008 does not apply and the utility shall pay franchise fees to a municipality as required by the utility's franchise agreement with the municipality. After the date on which an electric utility subject to this subchapter implements customer choice, Section 33.008 applies. However, for purposes of computing the franchise fees as provided by Section 33.008(b), the calendar year immediately preceding the implementation of customer choice shall be substituted for the year 1998.

(c) On or after January 1, 2007, an electric utility subject to this subchapter may choose to participate in customer choice. An electric utility that chooses to participate in customer choice shall file a transition to competition plan with the commission. This transition to competition plan shall identify how utilities subject to this subchapter intend to mitigate market power and achieve full customer choice, including specific alternatives for constructing additional transmission facilities, auctioning rights to generation capacity, divesting generation capacity, or any other measure that is consistent with the public interest. The utility shall also include in the transition to competition plan a provision to establish a price to beat for residential customers and commercial customers having a peak load of 1,000 kilowatts or less. The commission may prescribe additional information or provisions that must be included in the plan. The commission shall approve, modify, or reject a plan within 180 days after the date of a filing under this section; provided, however, that if a hearing is requested by any party to the proceeding, the 180-day deadline will be extended one day for each day of hearings. The transition to competition plan may be updated or amended annually, subject to commission approval until the applicable power region is certified as a qualifying power region under Section 39.152.

(d) On implementation of customer choice, an electric utility subject to this subchapter is subject to the provisions of this subtitle and Subtitle A to the same extent as other electric utilities, including the provisions of Chapter 37 concerning certificates of convenience and necessity.

(e) Notwithstanding Subsection (a), an electric utility subject to this subchapter that elects to deploy advanced metering and meter information networks may recover reasonable and necessary costs incurred in deploying advanced metering and meter information networks. An electric utility that elects to deploy advanced metering or meter information networks is subject to commission rules adopted under Sections 39.107(h) and (k). The commission shall ensure that any deployment plan approved under this section and any related customer surcharge:

(1) are not applicable to customer accounts that receive service at transmission voltage; and

(2) are consistent with commission rules related to advanced metering systems regarding:

(A) customer protections;

(B) data security, privacy, and ownership; and

(C) options given consumers to continue to receive service through a non-advanced meter.

(f) An electric utility subject to this subchapter that elects to deploy an advanced meter information network shall deploy the network as rapidly as practicable to allow customers to better manage energy use and control costs.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999. Amended by Acts 2001, 77th Leg., ch. 1041, Sec. 1, eff. June 15, 2001.

Amended by:

Acts 2011, 82nd Leg., R.S., Ch. 182 (S.B. 1150), Sec. 1, eff. May 28, 2011.

Acts 2019, 86th Leg., R.S., Ch. 170 (H.B. 986), Sec. 1, eff. May 24, 2019.

Acts 2019, 86th Leg., R.S., Ch. 610 (S.B. 936), Sec. 4, eff. September 1, 2019.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 28, eff. September 1, 2023.

Sec. 39.407. CUSTOMER CHOICE AND RELEVANT MARKET AND RELATED MATTERS. (a) If an electric utility chooses on or after January 1, 2007, to participate in customer choice, the commission may not authorize customer choice until the applicable power region has been certified as a qualifying power region under Section 39.152(a). Except as otherwise provided by this subsection, the commission shall certify that the requirements of Section 39.152(a)(3) are met for electric utilities subject to this subchapter only upon a finding that the total capacity owned and controlled by each such electric utility and its affiliates does not exceed 20 percent of the total installed generation capacity within the constrained geographic region served by each such electric utility plus the total available transmission capacity capable of delivering firm power and energy to that constrained geographic region. Not later than May 1, 2002, each electric utility subject to this subchapter shall submit to the electric utility restructuring legislative oversight committee an analysis of the needed transmission facilities necessary to make the electric utility's service area transmission capability comparable to areas within the ERCOT power region. On or after September 1, 2003, each electric utility subject to this subchapter shall file the utility's plans to develop the utility's transmission interconnections with the utility's power region or other adjacent power regions. The commission shall review the plan and not later than the 180th day after the date the plan is filed, determine the additional transmission facilities necessary to provide access to power and energy that is comparable to the access provided in areas within the ERCOT power region; provided, however, that if a hearing is requested by any party to the proceeding, the 180-day deadline will be extended one day for each day of hearings. The commission shall, as a part of the commission's approval of the plan, approve a rate rider mechanism for the recovery of the incremental costs of those facilities after the facilities are completed and in-service. A finding of need under this subsection shall meet the requirements of Sections 37.056(c)(1), (2), and (4)(E). The commission may certify that the requirements of Section 39.152(a)(3) are met for electric utilities subject to this subchapter if the commission finds that:

(1) each such utility has sufficient transmission facilities to provide customers access to power and energy from capacity controlled by suppliers not affiliated with the incumbent utility that is comparable to the access to power and energy from capacity controlled by suppliers not affiliated with the incumbent utilities in areas of the ERCOT power region; and

(2) the total capacity owned and controlled by each such electric utility and its affiliates does not exceed 20 percent of the total installed generation capacity within the power region.

(b) In the area of a power region served by an electric utility subject to this subchapter, the electric utility may not choose to participate in customer choice unless the affiliated power generation company makes a commitment to maintain and does maintain rates that are based on cost of service for any electric cooperative or municipally owned utility that was a wholesale customer on the date the utility chooses to participate in customer choice and was purchasing power at rates that were based on cost of service. This subsection requires a power generation company to sell power at rates that are based on cost of service, notwithstanding the expiration of a contract for that service, until the requirements of Section 39.152(a) are met.

(c) If the requirements of Section 39.152(a) have not been met for an electric utility subject to this subchapter when the electric utility chooses to participate in customer choice, then any power generation company in the power region affiliated with an electric utility subject to this subchapter shall maintain adequate supply and facilities to provide electric service to persons who were retail customers of the electric utility on the date the utility chooses to participate in customer choice. The obligation provided by this subsection remains in effect until the commission determines that the requirements of Section 39.152(a) have been met for the region.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by Acts 2001, 77th Leg., ch. 1041, Sec. 1, eff. June 15, 2001.

For expiration of this section, see Subsection (g).

Sec. 39.408. HIRING ASSISTANCE FOR FEDERAL PROCEEDINGS. (a) The commission may retain any consultant, accountant, auditor, engineer, or attorney the commission considers necessary to represent the commission in a proceeding before the Federal Energy Regulatory Commission, or before a court reviewing proceedings of that federal commission, related to:

(1) the relationship of an electric utility subject to this subchapter to a power region, regional transmission organization, or independent system operator;

(2) the approval of an agreement among the electric utility and the electric utility's affiliates concerning the coordination of the operations of the electric utility and the electric utility's affiliates; or

(3) other matters related to the electric utility subject to this subchapter that may affect the ultimate rates paid by retail customers in this state.

(b) Assistance for which a consultant, accountant, auditor, engineer, or attorney may be retained under Subsection (a) may include:

(1) conducting a study;

(2) conducting an investigation;

(3) presenting evidence;

(4) advising the commission; or

(5) representing the commission.

(c) The electric utility shall pay timely the reasonable costs of the services of a person retained under Subsection (a), as determined by the commission. The total costs an electric utility is required to pay under this subsection may not exceed $1.5 million in a 12-month period.

(d) The commission shall allow the electric utility to recover both the total costs the electric utility paid under Subsection (c) and the carrying charges for those costs through a rider established annually to recover the costs paid and carrying charges incurred during the preceding calendar year. The rider may not be implemented before the rider is reviewed and approved by the commission.

(e) The commission shall consult the attorney general before the commission retains a consultant, accountant, auditor, or engineer under Subsection (a). The retention of an attorney under Subsection (a) is subject to the approval of the attorney general under Section 402.0212, Government Code.

(f) The commission shall be precluded from engaging any individual who is required to register under Section 305.003, Government Code.

(g) This section expires September 1, 2029.

Added by Acts 2015, 84th Leg., R.S., Ch. 849 (S.B. 932), Sec. 1, eff. September 1, 2015.

Amended by:

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 29, eff. September 1, 2023.

Sec. 39.409. RECOUPMENT OF TRANSITION TO COMPETITION COSTS. An electric utility subject to this subchapter is entitled to recover, as provided by this section, all reasonable and necessary expenditures made or incurred before September 1, 2001, to comply with the provisions of this chapter. Not later than December 1, 2001, each electric utility subject to this subchapter may file with the commission an application for recovery detailing the amounts spent or incurred. After notice and hearing, the commission shall review the amounts and, if found to be reasonable and necessary, approve a transition to competition retail rate rider mechanism for the recovery of the approved transition to competition costs. A rate rider implemented to recover approved transition to competition costs shall expire not later than December 31, 2006.

Added by Acts 2001, 77th Leg., ch. 1041, Sec. 2, eff. June 15, 2001.

Sec. 39.410. CONTRACTUAL OBLIGATIONS. This subchapter may not:

(1) interfere with or abrogate the rights or

obligations of any party, including a retail or wholesale customer, to a contract with an investor-owned electric utility, river authority, municipally owned utility, or electric cooperative;

(2) interfere with or abrogate the rights or obligations of a party under a contract or agreement concerning certificated utility service areas; or

(3) result in a change in wholesale power costs to wholesale customers in Texas purchasing electricity under wholesale power contracts the pricing provisions of which are based on formulary rates, fuel adjustments, or average system costs.

Added by Acts 2001, 77th Leg., ch. 1041, Sec. 2, eff. June 15, 2001.

SUBCHAPTER J. TRANSITION TO COMPETITION IN CERTAIN NON-ERCOT AREAS

Sec. 39.451. APPLICABILITY. This subchapter applies only to an investor-owned electric utility that is operating solely outside of ERCOT in areas of this state that were included in the Southeastern Electric Reliability Council on January 1, 2005.

Added by Acts 2005, 79th Leg., Ch. 1072 (H.B. 1567), Sec. 1, eff. June 18, 2005.

Sec. 39.452. REGULATION OF UTILITY AND TRANSITION TO COMPETITION. (a) Until the date on which an electric utility subject to this subchapter is authorized by the commission to implement customer choice under Section 39.453, the rates of the electric utility shall be regulated under traditional cost-of-service regulation and the electric utility is subject to all applicable regulatory authority prescribed by this subtitle and Subtitle A, including Chapters 14, 32, 33, 36, and 37.

(b) An electric utility subject to this subchapter shall propose a competitive generation tariff to allow eligible customers the ability to contract for competitive generation. The commission shall approve, reject, or modify the proposed tariff not later than September 1, 2010. The tariffs subject to this subsection may not be considered to offer a discounted rate or rates under Section 36.007, and the utility's rates shall be set, in the proceeding in which the tariff is adopted, to recover any costs unrecovered as a result of the implementation of the tariff. The commission shall ensure that a competitive generation tariff shall not be implemented in a manner that harms the sustainability or competitiveness of manufacturers that choose not to take advantage of competitive generation. Pursuant to the competitive generation tariff, an electric utility subject to this subsection shall purchase competitive generation service, selected by the customer, and provide the generation at retail to the customer. An electric utility subject to this subsection shall provide and price retail transmission service, including necessary ancillary services, to retail customers who choose to take advantage of the competitive generation tariff at a rate that is unbundled from the utility's cost of service. Such customers shall not be considered wholesale transmission customers. Notwithstanding any other provision of this chapter, the commission may not issue a decision relating to a competitive generation tariff that is contrary to an applicable decision, rule, or policy statement of a federal regulatory agency having jurisdiction.

(c) That portion of any commission order issued before the effective date of this section requiring the electric utility to comply with a provision of this chapter is void.

(d) Until the date on which an electric utility subject to this subchapter implements customer choice:

(1) the provisions of this chapter do not apply to that electric utility, other than this subchapter, Sections 39.1516 and 39.905, the provisions relating to the duty to obtain a permit from the Texas Commission on Environmental Quality for an electric generating facility and to reduce emissions from an electric generating facility, and the provisions of Subchapter G that pertain to the recovery and securitization of hurricane reconstruction costs authorized by Sections 39.458-39.463; and

(2) the electric utility is not subject to a rate freeze and, subject to the limitation provided by Subsection (b), may file for rate changes under Chapter 36 and for approval of one or more of the rate rider mechanisms authorized by Sections 39.454 and 39.455.

(e) An electric utility subject to this subchapter may proceed with and complete jurisdictional separation to establish two vertically integrated utilities, one of which is solely subject to the retail jurisdiction of the commission and one of which is solely subject to the retail jurisdiction of the Louisiana Public Service Commission.

(f) Not later than January 1, 2006, an electric utility subject to this subchapter shall file a plan with the commission for identifying the applicable power region or power regions, enumerating the steps to achieve the certification of a power region in accordance with Section 39.453, and specifying the schedule for achieving the certification of a power region. The utility may amend the plan as appropriate. The commission may, on its own motion or the motion of any affected person, initiate a proceeding to certify a qualified power region under Section 39.152 when the conditions supporting such a proceeding exist.

(g) Not later than the earlier of January 1, 2007, or the 90th day after the date the applicable power region is certified in accordance with Section 39.453, the electric utility shall file a transition to competition plan. The transition to competition plan must:

(1) identify how the electric utility intends to mitigate market power and to achieve full customer choice, including specific alternatives for constructing additional transmission facilities, auctioning rights to generation capacity, divesting generation capacity, or any other measure that is consistent with the public interest;

(2) include a provision to reinstate a customer choice pilot project and to establish a price to beat for residential customers and commercial customers having a peak load of 1,000 kilowatts or less; and

(3) include any other additional information or provisions that the commission may require.

(h) The commission shall approve, modify, or reject a plan filed under Subsection (g) not later than the 180th day after the date the plan is filed unless a hearing is requested by any party to the proceeding. A modification to the plan by the commission may not be in conflict with the jurisdiction or orders of the Federal Energy Regulatory Commission or result in significant additional cost without allowing for timely recovery for that cost. If a hearing is requested, the 180-day deadline is extended one day for each day of the hearing. The transition to competition plan shall be updated or amended annually, subject to commission approval, until the initiation of customer choice by an electric utility subject to this subchapter. Consistent with its jurisdiction, the commission shall have the authority in approving or modifying the transition to competition plan to require the electric utility to take reasonable steps to facilitate the development of a wholesale generation market within the boundaries of the electric utility's service territory.

(i) Notwithstanding any other provision of this chapter, if the commission has not approved the transition to competition plan under this section before January 1, 2009, an electric utility subject to this subchapter shall cease all activities relating to the transition to competition under this section. The commission may, on its own motion or the motion of any affected person, initiate a proceeding under Section 39.152 to certify a power region to which the utility belongs as a qualified power region when the conditions supporting such a proceeding exist. The commission may not approve a plan under Subsection (g) until the expiration of four years from the time that the commission certifies a power region under Subsection (f). If after the expiration of four years from the time the commission certifies a power region under Subsection (f), and after notice and a hearing, the commission determines consistent with the study required by Section 5, S.B. No. 1492, Acts of the 81st Legislature, Regular Session, 2009, that the electric utility cannot comply with Section 38.073, it shall consider approving a plan under Subsection (g).

(j) Notwithstanding any other provision of this subtitle, in awarding a certificate of convenience and necessity or allowing cost recovery for purchased power by an electric utility subject to this section, the commission shall ensure in its determination that the provisions of Sections 37.056(c)(4)(D) and (E) are met and that the generating facility or the purchased power agreement satisfies the identified reliability needs of the utility.

(k) Notwithstanding Subsection (d), an electric utility subject to this subchapter that elects to deploy advanced metering and meter information networks may recover reasonable and necessary costs incurred in deploying advanced metering and meter information networks. An electric utility that elects to deploy advanced metering or meter information networks is subject to commission rules adopted under Sections 39.107(h) and (k). The commission shall ensure that any deployment plan approved under this section and any related customer surcharge:

(1) are not applicable to customer accounts that receive service at transmission voltage; and

(2) are consistent with commission rules related to advanced metering systems regarding:

(A) customer protections;

(B) data security, privacy, and ownership; and

(C) options given consumers to continue to receive service through a non-advanced meter.

(l) An electric utility subject to this subchapter that elects to deploy an advanced meter information network shall deploy the network as rapidly as practicable to allow customers to better manage energy use and control costs.

Added by Acts 2005, 79th Leg., Ch. 1072 (H.B. 1567), Sec. 1, eff. June 18, 2005.

Amended by:

Acts 2006, 79th Leg., 3rd C.S., Ch. 11 (H.B. 163), Sec. 1, eff. May 31, 2006.

Acts 2009, 81st Leg., R.S., Ch. 1226 (S.B. 1492), Sec. 3, eff. June 19, 2009.

Acts 2017, 85th Leg., R.S., Ch. 31 (S.B. 1145), Sec. 1, eff. May 18, 2017.

Acts 2019, 86th Leg., R.S., Ch. 610 (S.B. 936), Sec. 5, eff. September 1, 2019.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 30, eff. September 1, 2023.

For expiration of this section, see Subsection (g).

Sec. 39.4525. HIRING ASSISTANCE FOR FEDERAL PROCEEDINGS. (a) The commission may retain any consultant, accountant, auditor, engineer, or attorney the commission considers necessary to represent the commission in a proceeding before the Federal Energy Regulatory Commission, or before a court reviewing proceedings of that federal commission, related to:

(1) the relationship of an electric utility subject to this subchapter to a power region, regional transmission organization, or independent system operator;

(2) the approval of an agreement among the electric utility and the electric utility's affiliates concerning the coordination of the operations of the electric utility and the electric utility's affiliates; or

(3) other matters related to the electric utility subject to this subchapter that may affect the ultimate rates paid by retail customers in this state.

(b) Assistance for which a consultant, accountant, auditor, engineer, or attorney may be retained under Subsection (a) may include:

(1) conducting a study;

(2) conducting an investigation;

(3) presenting evidence;

(4) advising the commission; or

(5) representing the commission.

(c) The electric utility shall pay timely the reasonable costs of the services of a person retained under Subsection (a), as determined by the commission. The total costs an electric utility is required to pay under this subsection may not exceed $1.5 million in a 12-month period.

(d) The commission shall allow the electric utility to recover both the total costs the electric utility paid under Subsection (c) and the carrying charges for those costs through a rider established annually to recover the costs paid and carrying charges incurred during the preceding calendar year. The rider may not be implemented before the rider is reviewed and approved by the commission.

(e) The commission shall consult the attorney general before the commission retains a consultant, accountant, auditor, or engineer under Subsection (a). The retention of an attorney under Subsection (a) is subject to the approval of the attorney general under Section 402.0212, Government Code.

(f) The commission shall be precluded from engaging any individual who is required to register under Section 305.003, Government Code.

(g) This section expires September 1, 2029.

Added by Acts 2011, 82nd Leg., R.S., Ch. 100 (S.B. 1153), Sec. 1, eff. May 20, 2011.

Amended by:

Acts 2015, 84th Leg., R.S., Ch. 849 (S.B. 932), Sec. 2, eff. September 1, 2015.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 31, eff. September 1, 2023.

Sec. 39.453. CUSTOMER CHOICE AND RELEVANT MARKET AND RELATED MATTERS. (a) The commission may not authorize customer choice until the commission certifies the applicable power region as a qualifying power region under Section 39.152(a). Sections 39.152(b)-(d) also apply to the electric utility and commission in determining whether to certify the applicable power region.

(b) The commission shall certify that the requirement of Section 39.152(a)(3) is met for an electric utility subject to this subchapter only if the commission finds that the total capacity owned and controlled by the electric utility and the utility's affiliates does not exceed 20 percent of the total installed generation capacity within the power region of that utility.

Added by Acts 2005, 79th Leg., Ch. 1072 (H.B. 1567), Sec. 1, eff. June 18, 2005.

Sec. 39.454. RECOUPMENT OF TRANSITION TO COMPETITION COSTS. An electric utility subject to this subchapter is entitled to recover, as provided by this section, all reasonable and necessary expenditures made or incurred before the effective date of this section to comply with this chapter, to the extent the costs have not otherwise been recovered. The electric utility may file with the commission an application for recovery that gives details of the amounts spent or incurred. After notice and hearing, the commission shall review the amounts and, if the amounts are found to be reasonable and necessary and not otherwise previously recovered, approve a transition to competition retail rate rider mechanism for the recovery of the approved transition to competition costs. A rate proceeding under Chapter 36 is not required to implement the rider. A rate rider implemented to recover approved transition to competition costs shall provide for recovery of those costs over a period not to exceed 15 years, with appropriate carrying costs.

Added by Acts 2005, 79th Leg., Ch. 1072 (H.B. 1567), Sec. 1, eff. June 18, 2005.

Sec. 39.455. RECOVERY OF INCREMENTAL CAPACITY COSTS. An electric utility subject to this subchapter is entitled to recover, through a rate rider mechanism, reasonable and necessary costs of incremental resources required to meet load requirements to the extent those costs result in the utility expending more for capacity costs under purchase power agreements than were included in the utility's last base rate case, adjusted for load growth. Any rider under this section shall be implemented after review and approval by the commission, after notice and opportunity for hearing. Following the initial implementation of the rider, an electric utility subject to this subchapter may request revisions semiannually, after notice and opportunity for hearing, on the dates provided in the commission's rules for filing petitions to revise the utility's fuel factor. In conjunction with the utility's fuel reconciliation proceedings, the commission shall reconcile the costs recovered under the rider and the actual incremental capacity costs eligible for recovery under this section. The rider shall expire on the introduction of customer choice or on the implementation of rates resulting from the filing of a Subchapter C, Chapter 36, rate proceeding. In no event may the amount recovered annually under the rider exceed five percent of the utility's annual base rate revenues.

Added by Acts 2005, 79th Leg., Ch. 1072 (H.B. 1567), Sec. 1, eff. June 18, 2005.

Sec. 39.456. FRANCHISE AGREEMENTS. A municipality, with the agreement of an electric utility, may accelerate the expiration date of a franchise agreement that was in existence on September 1, 1999. Any new franchise agreement must be approved by the governing body of the municipality. To the extent that a new franchise agreement would result in an increase in the payment of franchise fees to the municipality, and subject to the terms of the franchise agreement, either the electric utility or the municipality, without the need for a rate proceeding under Chapter 36, may file with the commission for approval of a rider for the electric utility's recovery of franchise payments resulting from the agreement, so long as such rider is collected only from customers of the electric utility that are located within the boundaries of the municipality.

Added by Acts 2005, 79th Leg., Ch. 1072 (H.B. 1567), Sec. 1, eff. June 18, 2005.

Sec. 39.457. CONTRACTUAL RIGHTS. In the event that the electric utility subject to this subchapter either merges, consolidates, or otherwise becomes affiliated with another owner of electric generation, or completes the jurisdictional separation authorized by Section 39.452(e) and the resulting vertically integrated utility proposes to join a regional transmission organization, and either action adversely affects the rights or obligations of an electric cooperative under a wholesale generation or transmission agreement entered into before the effective date of this subchapter or otherwise adversely affects the electric cooperative's access to its existing generation resources under said agreements, then the utility shall submit a proposal agreeable to the cooperative and the utility for addressing such rights and obligations in the appropriate regulatory proceeding. Such proposal shall be consistent with applicable law regarding the rights and obligations of the electric cooperative and the utility under such existing generation or transmission agreements.

Added by Acts 2005, 79th Leg., Ch. 1072 (H.B. 1567), Sec. 1, eff. June 18, 2005.

Sec. 39.458. RECOVERY AND SECURITIZATION OF HURRICANE RECONSTRUCTION COSTS; PURPOSE. (a) The purpose of this section and of Sections 39.459-39.463 is to enable an electric utility subject to this subchapter to obtain timely recovery of hurricane reconstruction costs and to use securitization financing to recover these costs, because that type of debt will lower the carrying costs associated with the recovery of hurricane reconstruction costs relative to the costs that would be incurred using conventional financing methods. The proceeds of the transition bonds may be used only for the purposes of reducing the amount of recoverable hurricane reconstruction costs, as determined by the commission in accordance with this subchapter, through the refinancing or retirement of utility debt or equity.

(b) It is the intent of the legislature that:

(1) securitization of hurricane reconstruction costs will be subject to the same procedures, standards, and protections for the securitization of stranded costs and regulatory assets under Subchapter G in effect on the effective date of this section, except as provided by this subchapter; and

(2) the commission will ensure that securitization of hurricane reconstruction costs provides greater tangible and quantifiable benefits to ratepayers than would have been achieved without the issuance of transition bonds.

Added by Acts 2006, 79th Leg., 3rd C.S., Ch. 11 (H.B. 163), Sec. 2, eff. May 31, 2006.

Sec. 39.459. HURRICANE RECONSTRUCTION COSTS. (a) In this subchapter:

(1) "Hurricane reconstruction costs" means reasonable and necessary costs, including costs expensed, charged to the storm reserve, or capitalized, that are incurred by an electric utility subject to this subchapter due to any activity or activities conducted by or on behalf of the electric utility in connection with the restoration of service associated with electric power outages affecting customers of the electric utility as the result of Hurricane Rita, including mobilization, staging, and construction,

reconstruction, replacement, or repair of electric generation, transmission, distribution, or general plant facilities.

(2) "Hurricane Rita" means the hurricane of that name that struck the coastal region of this state in September 2005.

(b) If the commission determines it to be appropriate, hurricane reconstruction costs may include carrying costs from the date on which the hurricane reconstruction costs were incurred until the date that transition bonds are issued.

(c) To the extent a utility subject to this subchapter receives insurance proceeds, governmental grants, or any other source of funding that compensates it for hurricane reconstruction costs, those amounts shall be used to reduce the utility's hurricane reconstruction costs recoverable from customers. If the timing of a utility's receipt of those amounts prevents their inclusion as a reduction to the hurricane reconstruction costs that are securitized, the commission shall take those amounts into account in:

(1) the utility's next base rate proceeding; or

(2) any proceeding in which the commission considers hurricane reconstruction costs.

Added by Acts 2006, 79th Leg., 3rd C.S., Ch. 11 (H.B. 163), Sec. 2, eff. May 31, 2006.

Sec. 39.460. STANDARDS AND PROCEDURES GOVERNING SECURITIZATION OF HURRICANE RECONSTRUCTION COSTS. (a) The procedures and standards of this subchapter and the provisions of Subchapter G govern the application for, and the commission's issuance of, a financing order to provide for the securitization of hurricane reconstruction costs by an electric utility subject to this subchapter.

(b) Subject to the standards, procedures, and tests contained in this subchapter and Subchapter G, the commission shall adopt a financing order on the application of the utility to recover its hurricane reconstruction costs. On the commission's issuance of a financing order allowing for recovery and securitization of hurricane reconstruction costs, the provisions of this subchapter and Subchapter G continue to govern the financing order and the rights and interests established in the order, and this subchapter and Subchapter G continue to govern any transition bonds issued pursuant to the financing order. To the extent any conflict exists between the provisions of this subchapter and Subchapter G in cases involving the securitization of hurricane reconstruction costs, the provisions of this subchapter control.

(c) For purposes of this subchapter, "financing order," as defined by Section 39.302 and as used in Subchapter G, includes a financing order authorizing the securitization of hurricane reconstruction costs.

(d) For purposes of this subchapter, "qualified costs," as defined by Section 39.302 and as used in Subchapter G, includes 100 percent of the electric utility's hurricane reconstruction costs together with the costs of issuing, supporting, and servicing transition bonds and any costs of retiring and refunding existing debt and equity securities of an electric utility subject to this subchapter in connection with the issuance of transition bonds. For purposes of this subchapter, the term also includes the costs to the commission of acquiring professional services for the purpose of evaluating proposed transactions under this subchapter.

(e) For purposes of this subchapter, "transition bonds," as defined by Section 39.302 and as used in Subchapter G, includes transition bonds issued in association with the recovery of hurricane reconstruction costs. Transition bonds issued to securitize hurricane reconstruction costs may be called "hurricane reconstruction bonds" or may be called by any other name acceptable to the issuer and the underwriters of the transition bonds.

(f) For purposes of this subchapter, "transition charges," as defined by Section 39.302 and as used in Subchapter G, includes nonbypassable amounts to be charged for the use of electric services, approved by the commission under a financing order to recover hurricane reconstruction costs, that shall be collected by an electric utility subject to this subchapter, its successors, an assignee, or other collection agents as provided for in the financing order.

(g) Notwithstanding Section 39.303(c), hurricane reconstruction costs shall be functionalized and allocated to customers in the same manner as the corresponding facilities and related expenses are functionalized and allocated in the utility's current base rates.

(h) The amount of any accumulated deferred federal income taxes offset, used to determine the securitization total, may not be considered in future rate proceedings. Any tax obligation of the electric utility arising from its receipt of securitization bond proceeds, or from the collection and remittance of transition charges, shall be recovered by the electric utility through the commission's implementation of Section 39.458, Section 39.459, this section, and Sections 39.461-39.463.

(i) If the commission determines that recovery of all or any portion of an electric utility's hurricane reconstruction costs using securitization is not beneficial to ratepayers of the electric utility, under one or more of the tests applied to determine those benefits, the commission shall permit the electric utility to recover the entirety of the hurricane reconstruction costs through an appropriate customer surcharge mechanism, including appropriate carrying costs, provided that the electric utility has not securitized any portion of its hurricane reconstruction costs. A rate proceeding under Chapter 36 may not be required to determine and implement this surcharge mechanism. A rider adopted under this subsection must expire on the implementation of rates resulting from the filing of a Subchapter C, Chapter 36, rate proceeding.

Added by Acts 2006, 79th Leg., 3rd C.S., Ch. 11 (H.B. 163), Sec. 2, eff. May 31, 2006.

Sec. 39.461. NONBYPASSABLE CHARGES. The commission may include terms in the financing order to ensure that the imposition and collection of transition charges associated with the recovery of hurricane reconstruction costs are nonbypassable by imposing restrictions on bypassability of the type provided for in this chapter or by alternative means of ensuring nonbypassability, as the commission considers appropriate, consistent with the purposes of securitization.

Added by Acts 2006, 79th Leg., 3rd C.S., Ch. 11 (H.B. 163), Sec. 2, eff. May 31, 2006.

Sec. 39.462. DETERMINATION OF HURRICANE RECONSTRUCTION COSTS. (a) An electric utility subject to this subchapter is entitled to recover hurricane reconstruction costs consistent with the provisions of this subchapter and is entitled to seek recovery of amounts not recovered under this subchapter, including hurricane reconstruction costs not yet incurred at the time an application is filed under Subsection (b), in its next base rate proceeding or through any other proceeding authorized by Subchapter C, Chapter 36.

(b) The commission shall issue an order determining the amount of hurricane reconstruction costs eligible for recovery and securitization not later than the 150th day after the date an electric utility subject to this subchapter files an application seeking that determination. The 150-day period begins on the date the electric utility files the application, even if the filing occurs before the effective date of this section.

(c) On issuance by the commission of an order determining the amount of eligible hurricane reconstruction costs, an electric utility subject to this subchapter may file an application for a financing order, which shall be governed by the procedures in Subchapter G.

(d) To the extent the commission has made a determination of the eligible hurricane reconstruction costs of an electric utility subject to this subchapter before the effective date of this section, that determination may provide the basis for the utility's application for a financing order pursuant to this subchapter and Subchapter G. A previous commission determination does not preclude the utility from requesting recovery of additional hurricane reconstruction costs eligible for recovery under this subchapter, but not previously authorized by the commission.

(e) A rate proceeding under Chapter 36 is not required to determine the amount of recoverable hurricane reconstruction costs as provided by this section.

Added by Acts 2006, 79th Leg., 3rd C.S., Ch. 11 (H.B. 163), Sec. 2, eff. May 31, 2006.

Sec. 39.463. SEVERABILITY. Effective on the date the first utility transition bonds associated with hurricane reconstruction costs are issued under this subchapter, if any provision in this title or portion of this title is held to be invalid or is invalidated, superseded, replaced, repealed, or expires for any reason, that occurrence does not affect the validity or continuation of this subchapter, Subchapter G as it applies to an electric utility subject to this subchapter, or any part of those provisions, or any other provision of this title that is relevant to the issuance, administration, payment, retirement, or refunding of transition bonds or to any actions of the electric utility, its successors, an assignee, a collection agent, or a financing party, and those provisions shall remain in full force and effect.

Added by Acts 2006, 79th Leg., 3rd C.S., Ch. 11 (H.B. 163), Sec. 2, eff. May 31, 2006.

SUBCHAPTER K. TRANSITION TO COMPETITION FOR CERTAIN AREAS OUTSIDE OF ERCOT

Sec. 39.501. APPLICABILITY. (a) This subchapter applies to an investor-owned electric utility:

(1) that is operating solely outside of ERCOT in areas of this state that were included in the Southwest Power Pool on January 1, 2008;

(2) that was not affiliated with the Southeastern Electric Reliability Council on January 1, 2008; and

(3) to which Subchapter I does not apply.

(b) The legislature finds that an electric utility subject to this subchapter is unable at this time to offer fair competition and reliable service to all retail customer classes in the area served by the utility. As a result, the introduction of retail competition for such an electric utility is delayed until fair competition and reliable service are available to all retail customer classes as determined under this subchapter.

Added by Acts 2009, 81st Leg., R.S., Ch. 128 (S.B. 547), Sec. 1, eff. September 1, 2009.

Sec. 39.502. COST-OF-SERVICE REGULATION. (a) Until the date on which an electric utility subject to this subchapter is authorized by the commission under Section 39.503(f) to implement retail customer choice, the rates of the utility are subject to regulation under Chapter 36.

(b) Until the date on which an electric utility subject to this subchapter implements customer choice, the provisions of this chapter, other than this subchapter and Sections 39.1516 and 39.905, do not apply to that utility.

Added by Acts 2009, 81st Leg., R.S., Ch. 128 (S.B. 547), Sec. 1, eff. September 1, 2009.

Amended by:

Acts 2019, 86th Leg., R.S., Ch. 610 (S.B. 936), Sec. 6, eff. September 1, 2019.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 32, eff. September 1, 2023.

Sec. 39.5021. METERING. (a) Notwithstanding Section 39.502, an electric utility subject to this subchapter that elects to deploy advanced metering and meter information networks may recover reasonable and necessary costs incurred in deploying advanced metering and meter information networks. An electric utility that elects to deploy advanced metering or meter information networks is subject to commission rules adopted under Sections 39.107(h) and (k). The commission shall ensure that any deployment plan approved under this section and any related customer surcharge:

(1) are not applicable to customer accounts that receive service at transmission voltage; and

(2) are consistent with commission rules related to advanced metering systems regarding:

(A) customer protections;

(B) data security, privacy, and ownership; and

(C) options given consumers to continue to receive service through a non-advanced meter.

(b) An electric utility subject to this subchapter that elects to deploy an advanced meter information network shall deploy the network as rapidly as practicable to allow customers to better manage energy use and control costs.

Added by Acts 2019, 86th Leg., R.S., Ch. 33 (H.B. 1595), Sec. 1, eff. May 14, 2019.

Sec. 39.503. TRANSITION TO COMPETITION. (a) The events prescribed by Subsections (b)-(f) shall be followed to introduce retail competition in the service area of an electric utility subject to this subchapter. The commission may modify the sequence of events required by Subsections (b)-(e), but not the substance of the requirements. Full retail competition may not begin in the service area of an electric utility subject to this subchapter until all actions prescribed by those subsections are completed.

(b) The first stage for the transition to competition consists of the following activities:

(1) approval of a regional transmission organization by the Federal Energy Regulatory Commission for the power region that includes the electric utility's service area and commencement of independent operation of the transmission network under the approved regional transmission organization;

(2) development of retail market protocols to facilitate retail competition; and

(3) completion of an expedited proceeding to develop non-bypassable delivery rates for the customer choice pilot project to be implemented under Subsection (c)(1).

(c) The second stage for the transition to competition consists of the following activities:

(1) initiation of the customer choice pilot project in accordance with Section 39.104;

(2) development of a balancing energy market, a market for ancillary services, and a market-based congestion management system for the wholesale market in the power region in which the regional transmission organization operates; and

(3) implementation of a seams agreement with adjacent power regions to reduce barriers to entry and facilitate competition.

(d) The third stage for the transition to competition consists of the following activities:

(1) the electric utility filing with the commission:

(A) an application for business separation in accordance with Section 39.051;

(B) an application for unbundled transmission and distribution rates in accordance with Section 39.201;

(C) an application for certification of a qualified power region in accordance with Section 39.152; and

(D) an application for price-to-beat rates in accordance with Section 39.202;

(2) the commission:

(A) approving a business separation plan for the utility;

(B) setting unbundled transmission and distribution rates for the utility;

(C) certifying a qualified power region, which includes conducting a formal evaluation of wholesale market power in the region, in accordance with Section 39.152;

(D) setting price-to-beat rates for the utility; and

(E) determining which competitive energy services must be separated from regulated utility activities in accordance with Section 39.051; and

(3) completion of the 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, by the regional transmission organization, the registration agent, and market participants.

(e) The fourth stage for the transition to competition consists of the following activities:

(1) commission evaluation of the results of the pilot project;

(2) initiation by the electric utility of a capacity auction in accordance with Section 39.153 at a time to be determined by the commission; and

(3) separation by the utility of competitive energy

services from its regulated utility activities, in accordance with the commission order approving the separation of competitive energy services.

(f) The fifth stage for the transition to competition consists of the following activities:

(1) evaluation by the commission of whether the electric utility can offer fair competition and reliable service to all retail customer classes in the area served by the utility, and:

(A) if the commission concludes that the electric utility can offer fair competition and reliable service to all retail customer classes in the area served by the utility, the commission issuing an order initiating retail competition for the utility; and

(B) if the commission determines that the electric utility cannot offer fair competition and reliable service to all retail customer classes in the area served by the utility, the commission issuing an order further delaying retail competition for the utility; and

(2) on the issuance of an order from the commission initiating retail competition for the utility, completion by the utility of the business separation and unbundling in accordance with the commission order approving the unbundling.

Added by Acts 2009, 81st Leg., R.S., Ch. 128 (S.B. 547), Sec. 1, eff. September 1, 2009.

For expiration of this section, see Subsection (g).

Sec. 39.504. HIRING ASSISTANCE FOR FEDERAL PROCEEDINGS. (a) The commission may retain any consultant, accountant, auditor, engineer, or attorney the commission considers necessary to represent the commission in a proceeding before the Federal Energy Regulatory Commission, or before a court reviewing proceedings of that federal commission, related to:

(1) the relationship of an electric utility subject to this subchapter to a power region, regional transmission organization, or independent system operator;

(2) the approval of an agreement among the electric utility and the electric utility's affiliates concerning the

coordination of the operations of the electric utility and the electric utility's affiliates; or

(3) other matters related to the electric utility subject to this subchapter that may affect the ultimate rates paid by retail customers in this state.

(b) Assistance for which a consultant, accountant, auditor, engineer, or attorney may be retained under Subsection (a) may include:

(1) conducting a study;

(2) conducting an investigation;

(3) presenting evidence;

(4) advising the commission; or

(5) representing the commission.

(c) The electric utility shall pay timely the reasonable costs of the services of a person retained under Subsection (a), as determined by the commission. The total costs an electric utility is required to pay under this subsection may not exceed $1.5 million in a 12-month period.

(d) The commission shall allow the electric utility to recover both the total costs the electric utility paid under Subsection (c) and the carrying charges for those costs through a rider established annually to recover the costs paid and carrying charges incurred during the preceding calendar year. The rider may not be implemented before the rider is reviewed and approved by the commission.

(e) The commission shall consult the attorney general before the commission retains a consultant, accountant, auditor, or engineer under Subsection (a). The retention of an attorney under Subsection (a) is subject to the approval of the attorney general under Section 402.0212, Government Code.

(f) The commission shall be precluded from engaging any individual who is required to register under Section 305.003, Government Code.

(g) This section expires September 1, 2029.

Added by Acts 2015, 84th Leg., R.S., Ch. 849 (S.B. 932), Sec. 3, eff. September 1, 2015.

Amended by:

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 33, eff. September 1, 2023.

SUBCHAPTER L. TRANSITION TO COMPETITION AND OTHER PROVISIONS FOR CERTAIN AREAS OUTSIDE OF ERCOT

Sec. 39.551. APPLICABILITY. (a) This subchapter applies only to an investor-owned electric utility:

(1) that is operating solely outside of ERCOT in areas of this state that were included in the Western Electricity Coordinating Council on January 1, 2011;

(2) that was not affiliated with ERCOT on January 1, 2011; and

(3) to which Subchapters I, J, and K do not apply.

(b) The legislature finds that an electric utility subject to this subchapter is unable at this time to offer fair competition and reliable service to all retail customer classes in the area served by the utility. As a result, the introduction of retail competition for such an electric utility is delayed until fair competition and reliable service are available to all retail customer classes as determined under this subchapter.

Added by Acts 2011, 82nd Leg., R.S., Ch. 1113 (S.B. 1910), Sec. 1, eff. June 17, 2011.

Sec. 39.552. COST-OF-SERVICE REGULATION. (a) Until the date on which an electric utility subject to this subchapter is authorized by the commission under Section 39.553(f) to implement retail customer choice, the rates of the utility are subject to regulation under Chapter 36.

(b) Until the date on which an electric utility subject to this subchapter implements customer choice, the provisions of this chapter, other than this subchapter and Sections 39.1516 and 39.905, do not apply to that utility.

Added by Acts 2011, 82nd Leg., R.S., Ch. 1113 (S.B. 1910), Sec. 1, eff. June 17, 2011.

Amended by:

Acts 2019, 86th Leg., R.S., Ch. 610 (S.B. 936), Sec. 7, eff.

September 1, 2019.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 34, eff. September 1, 2023.

Sec. 39.5521. METERING. (a) Notwithstanding Section 39.552, an electric utility subject to this subchapter that elects to deploy advanced metering and meter information networks may recover reasonable and necessary costs incurred in deploying advanced metering and meter information networks. An electric utility that elects to deploy advanced metering or meter information networks is subject to commission rules adopted under Sections 39.107(h) and (k). The commission shall ensure that any deployment plan approved under this section and any related customer surcharge:

(1) are not applicable to customer accounts that receive service at transmission voltage; and

(2) are consistent with commission rules related to advanced metering systems regarding:

(A) customer protections;

(B) data security, privacy, and ownership; and

(C) options given consumers to continue to receive service through a non-advanced meter.

(b) An electric utility subject to this subchapter that elects to deploy an advanced meter information network shall deploy the network as rapidly as practicable to allow customers to better manage energy use and control costs.

Added by Acts 2019, 86th Leg., R.S., Ch. 168 (H.B. 853), Sec. 1, eff. May 24, 2019.

Sec. 39.553. TRANSITION TO COMPETITION. (a) The events prescribed by Subsections (b)-(f) shall be followed to introduce retail competition in the service area of an electric utility subject to this subchapter. The commission shall ensure that the listed items in each stage are completed before the next stage is initiated. Unless stated otherwise, the commission shall conduct each activity with the electric utility and other interested parties. The commission may modify the sequence of events required by Subsections (b)-(e), but not the substance of the requirements, if the commission finds good cause to do so. Full retail competition may not begin in the service area of an electric utility subject to this subchapter until all actions prescribed by those subsections are completed.

(b) The first stage for the transition to competition consists of the following activities:

(1) approval of a regional transmission organization by the Federal Energy Regulatory Commission for the power region that includes the electric utility's service area and commencement of independent operation of the transmission network under the approved regional transmission organization;

(2) development of retail market protocols to facilitate retail competition; and

(3) completion of an expedited proceeding to develop nonbypassable delivery rates for the customer choice pilot project to be implemented under Subsection (c)(1).

(c) The second stage for the transition to competition consists of the following activities:

(1) initiation of the customer choice pilot project in accordance with Section 39.104;

(2) development of a balancing energy market, a market for ancillary services, and a market-based congestion management system for the wholesale market in the power region in which the regional transmission organization operates; and

(3) implementation of a seams agreement with adjacent power regions to reduce barriers to entry and facilitate competition.

(d) The third stage for the transition to competition consists of the following activities:

(1) the electric utility filing with the commission:

(A) an application for business separation in accordance with Section 39.051;

(B) an application for unbundled transmission and distribution rates in accordance with Section 39.201;

(C) an application for certification of a qualified power region in accordance with Section 39.152; and

(D) an application for price-to-beat rates in accordance with Section 39.202;

(2) the commission:

(A) approving a business separation plan for the utility;

(B) setting unbundled transmission and distribution rates for the utility;

(C) certifying a qualified power region, which includes conducting a formal evaluation of wholesale market power in the region, in accordance with Section 39.152;

(D) setting price-to-beat rates for the utility; and

(E) determining which competitive energy services must be separated from regulated utility activities in accordance with Section 39.051; and

(3) completion of the 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, by the regional transmission organization, the registration agent, and market participants.

(e) The fourth stage for the transition to competition consists of the following activities:

(1) commission evaluation of the results of the pilot project;

(2) initiation by the electric utility of a capacity auction in accordance with Section 39.153 at a time to be determined by the commission; and

(3) separation by the utility of competitive energy services from its regulated utility activities, in accordance with the commission order approving the separation of competitive energy services.

(f) The fifth stage for the transition to competition consists of the following activities:

(1) evaluation by the commission of whether the electric utility can offer fair competition and reliable service to all retail customer classes in the area served by the utility, and:

(A) if the commission concludes that the electric utility can offer fair competition and reliable service to all retail customer classes in the area served by the utility, the commission issuing an order initiating retail competition for the utility; and

(B) if the commission determines that the electric utility cannot offer fair competition and reliable service to all retail customer classes in the area served by the utility, the commission issuing an order further delaying retail competition for the utility; and

(2) on the issuance of an order from the commission initiating retail competition for the utility, completion by the utility of the business separation and unbundling in accordance with the commission order approving the unbundling.

Added by Acts 2011, 82nd Leg., R.S., Ch. 1113 (S.B. 1910), Sec. 1, eff. June 17, 2011.

Sec. 39.554. INTERCONNECTION OF DISTRIBUTED RENEWABLE GENERATION. (a) In this section:

(1) "Distributed renewable generation" has the meaning assigned by Section 39.916.

(2) "Distributed renewable generation owner" means an owner of distributed renewable generation that is a retail electric customer.

(3) "Interconnection" has the meaning assigned by Section 39.916.

(b) A distributed renewable generation owner in the service area of an electric utility subject to this subchapter may request interconnection by filing an application for interconnection with the utility. An application for interconnection is subject to the utility's safety and reliability requirements. The utility's procedures for the submission and processing of an application for interconnection shall be consistent with rules adopted by the commission regarding interconnection.

(c) An electric utility that approves an application of a distributed renewable generation owner under Subsection (b):

(1) shall install, maintain, and retain ownership of the meter and metering equipment; and

(2) may install load research metering equipment on the premises of the owner, at no expense to the owner.

(d) At the request of an electric utility that approves an application of a distributed renewable generation owner under Subsection (b), the owner shall:

(1) provide and install a meter socket, a metering cabinet, or both a socket and cabinet at a location designated by the utility on the premises of the owner; and

(2) provide, at no expense to the utility, a suitable location for the utility to install meters and equipment associated with billing and load research.

(e) An electric utility that approves an application of a distributed renewable generation owner under Subsection (b) shall provide to the owner the metering options described by Section 39.916(f) and an option to interconnect with the utility through a single meter that runs forward and backward if:

(1) the owner:

(A) intends to interconnect the distributed renewable generation at an apartment house, as defined by Section 184.011, occupied by low-income elderly tenants that qualifies for master metering under Section 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 not more than 50 kilowatts; and

(2) the distributed renewable generation or qualifying facility that is the subject of the application is rated to produce an amount of electricity that is less than or equal to:

(A) the owner's estimated annual kilowatt hour consumption for a new apartment house or qualifying facility; or

(B) the amount of electricity the owner consumed in the year before installation of the distributed renewable generation or qualifying facility.

(f) For a distributed renewable generation owner that chooses interconnection through a single meter under Subsection (e):

(1) the amount of electricity the owner generates

through distributed renewable generation or a qualifying facility for a given billing period offsets the owner's consumption for that billing period; and

(2) any electricity the owner generates through distributed renewable generation or a qualifying facility that exceeds the owner's consumption for a given billing period shall be credited to the owner under Subsection (g).

(g) An electric utility that purchases surplus electricity under Subsection (f)(2) shall purchase the electricity from the distributed renewable generation owner at the cost of the utility as determined by commission rule. The utility shall take reasonable steps to inform the owner of the amount of surplus electricity purchased from the owner in kilowatt hours during the owner's most recent billing cycle. A credit balance of not more than $50 on the owner's monthly bill may be carried forward onto the owner's next monthly bill. The utility shall refund to the owner 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.

(h) In a base rate proceeding or fuel cost recovery proceeding conducted under Chapter 36, the commission shall ensure that any additional cost associated with the metering and payment options described by Subsections (e), (f), and (g) is allocated only to customer classes that include distributed renewable generation owners who have chosen those metering options.

Added by Acts 2011, 82nd Leg., R.S., Ch. 1113 (S.B. 1910), Sec. 1, eff. June 17, 2011.

Sec. 39.555. MARKETING OF ENERGY EFFICIENCY AND RENEWABLE ENERGY PROGRAMS. An electric utility subject to this subchapter may market an energy efficiency or renewable energy program directly to a retail electric customer in its service territory and provide rebate or incentive funds directly to a customer to promote or facilitate the success of programs implemented under Section 39.905.

Added by Acts 2011, 82nd Leg., R.S., Ch. 1113 (S.B. 1910), Sec. 1, eff. June 17, 2011.

SUBCHAPTER M. WINTER STORM URI DEFAULT BALANCE FINANCING

Sec. 39.601. PURPOSE. (a) The purpose of this subchapter is to address the Winter Storm Uri default balance, as defined by Section 39.602, in a manner that benefits the public interest by:

(1) enabling the independent organization to finance the payment of the default balance with debt obligations; and

(2) authorizing the commission to contract with the comptroller under Section 404.0241, Government Code, to finance the payment of the default balance with debt obligations.

(b) Financing the default balance in the manner provided by this subchapter will:

(1) allow wholesale market participants that are owed money to be paid in a more timely manner;

(2) replenish financial revenue auction receipts temporarily used by the independent organization to reduce the Winter Storm Uri-related amounts short-paid to the wholesale market participants; and

(3) allow the wholesale market to repay the default balance over time.

(c) The legislature finds that the financing authorized by this subchapter serves the public purpose of preserving the integrity of the electricity market in the ERCOT power region.

(d) The proceeds of debt obligations issued under this subchapter must be used solely for the purpose of financing default balances that otherwise would be or have been uplifted to the wholesale market.

(e) The commission shall ensure that the structuring and pricing of debt obligations issued under this subchapter result in the lowest financing costs consistent with market conditions and the terms of the commission's order. The present value calculation must use a discount rate equal to the proposed interest rate on the debt obligations.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.602. DEFINITIONS. In this subchapter:

(1) "Default balance" means an amount of money of not more than $800 million that includes only:

(A) amounts owed to the independent organization by competitive wholesale market participants from the period of emergency that otherwise would be or have been uplifted to other wholesale market participants;

(B) financial revenue auction receipts used by the independent organization to temporarily reduce amounts short-paid to wholesale market participants related to the period of emergency; and

(C) reasonable costs incurred by a state agency or the independent organization to implement a debt obligation order under Sections 39.603 and 39.604, including the cost of retiring or refunding existing debt.

(2) "Default charges" means charges assessed to wholesale market participants to repay amounts financed under this subchapter to pay the default balance.

(3) "Independent organization" means the independent organization certified under Section 39.151 for the ERCOT power region.

(4) "Period of emergency" means the period beginning 12:01 a.m., February 12, 2021, and ending 11:59 p.m., February 20, 2021.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.603. DEBT OBLIGATION ORDER. (a) On application by the independent organization, the commission by order may authorize the independent organization to establish a debt financing mechanism to finance the default balance if the commission finds that the debt obligations are needed to preserve the integrity of the wholesale market and the public interest, after considering:

(1) the need to timely replenish financial revenue auction receipts used by the independent organization to reduce amounts short-paid to wholesale market participants;

(2) the interests of wholesale market participants

that are owed balances; and

(3) the potential effects of uplifting those balances to the wholesale market without a financing vehicle.

(b) The order must state:

(1) the default balance to be financed; and

(2) the period over which the default charges must be assessed to repay the debt obligations, which may not exceed 30 years.

(c) The order must include an adjustment mechanism requiring the independent organization to adjust default charges to refund, over the remaining period of the default charges, any payments made by a market participant toward unpaid obligations from the period of emergency that were included in the financed default balance.

(d) The independent organization shall collect from and allocate among wholesale market participants the default charges using the same allocated pro rata share methodology under which the charges would otherwise be uplifted under the protocols in effect on March 1, 2021. The default charges must be assessed on all wholesale market participants, including market participants who are in default but still participating in the wholesale market and who enter the market after a debt obligation order is issued under this subchapter, and may be based on periodically updated transaction data to prevent market participants from engaging in behavior designed to avoid the default charges.

(e) Not later than the 30th day after the date the independent organization receives a default charge payment from a wholesale market participant, the independent organization shall remit the payment to the comptroller toward repayment of debt obligations in which the comptroller made an investment under Section 404.0241(b-1), Government Code, if applicable.

(f) Notwithstanding another provision of this subchapter, default charges may not be collected from or allocated to a market participant that:

(1) otherwise would be subject to a default charge solely as a result of acting as a central counterparty clearinghouse in wholesale market transactions in the ERCOT power

region; and

(2) is regulated as a derivatives clearing organization, as defined by Section 1a, Commodity Exchange Act (7 U.S.C. Section 1a).

(g) Not later than the 90th day after the date the independent organization files an application for an order under Subsection (a), the commission shall issue an order described by Subsection (a) or an order denying the application. The order becomes effective in accordance with its terms and the order, together with the default charges authorized in the order, shall be irrevocable and not subject to reduction, impairment, or adjustment by further action of the commission after the order takes effect. Notwithstanding this requirement, the commission may refinance any debt obligations created by an order issued under this subchapter if the commission determines that the refinancing is in the public interest, considering the interest of both the ERCOT market and the state's interest in the economic stabilization fund, and otherwise meets the requirements of this subchapter.

(h) An order described by Subsection (a) or (g) is not subject to rehearing by the commission. The order may be reviewed by appeal by a party to the proceeding to a Travis County district court that is filed not later than the 15th day after the date the order is signed by the commission. The judgment of the district court may be reviewed only by a direct appeal to the Supreme Court of Texas that is filed not later than the 15th day after the date of the entry of judgment. All appeals shall be heard and determined by the district court and the Supreme Court of Texas as expeditiously as possible with lawful precedence over other matters. Review on appeal shall be based solely on the record before the commission and briefs to the court and shall be limited to whether the order conforms to the constitution and laws of this state and the United States and is within the authority of the commission under this chapter.

(i) A debt obligation issued under this section is a nonrecourse debt secured solely by the default charges explicitly assessed to repay the obligation. The independent organization's obligations authorized under this section do not create personal liability for the independent organization.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.604. COMMISSION-AUTHORIZED FINANCING. (a) The commission may contract with another state agency with expertise in public financing to establish a debt financing mechanism for the payment of the default balance as defined in this subchapter, under an order that meets the requirements of Section 39.603. This section does not apply to a default balance securitized under Subchapter D, Chapter 41.

(b) The contracted state agency and any issuer, along with the independent organization, must be a party to the commission's proceedings that address the issuance of an order.

(c) In addition to the other applicable requirements of this subtitle, an order issued under this section must:

(1) require the sale, assignment, or other transfer to the contracted state agency of default charges created by the order and, following that sale, assignment, or transfer, require that default charges paid under any order be created, assessed, and collected as the property of the contracted state agency, subject to subsequent sale, assignment, or transfer by the contracted state agency as authorized under this subchapter;

(2) authorize:

(A) the issuance of debt obligations by the contracted state agency secured by a pledge of default charge revenue, and the application of the proceeds of those debt obligations, net of issuance costs, to the independent organization; or

(B) the acquisition of default charge revenue from the independent organization by the contracted state agency, financed:

(i) by a loan by an issuer to the contracted state agency of the proceeds of debt obligations, net of issuance costs; or

(ii) by the acquisition by an issuer from the contracted state agency of the default charge revenue and in each case the pledge of the revenue to the repayment of the loan or other debt obligation, as applicable; and

(3) authorize the independent organization to serve as collection agent to collect the default charges and transfer the collected default charges to the contracted state agency or the issuer, as appropriate.

(d) After issuance of the order, the contracted state agency shall arrange for the issuance of debt obligations, as specified by the order, by the contracted state agency or another issuer selected by the contracted state agency and approved by the commission.

(e) Debt obligations issued pursuant to an order issued under this section are secured only by the default charge revenue and any other funds pledged under the bond documents. No assets of the state or the independent organization are subject to claims by the holders of the debt obligations. Following assignment of the default charge revenue, the independent organization does not have any beneficial interest or claim of right in the revenue.

(f) Effective on the date the first debt obligations are issued under this subchapter, if any provision of this title or portion of this title is held to be invalid or is invalidated, superseded, replaced, or repealed, or expires for any reason, that occurrence does not affect the validity or continuation of this subchapter or any other provision of this title that is relevant to the issuance, administration, payment, retirement, or refunding of debt obligations authorized under this subchapter or to any actions of the independent organization, its successors, an assignee, a collection agent, the contracted state agency, or an issuer and those provisions shall remain in full force and effect.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.605. DEFAULT CHARGES NONBYPASSABLE. An order issued under Section 39.603 or 39.604 must:

(1) include terms ensuring that the imposition and collection of default charges authorized in the order shall be nonbypassable by wholesale market participants; and

(2) authorize the independent organization to establish appropriate fees and other methods for pursuing amounts owed from entities exiting the wholesale market.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.606. TRUE-UP MECHANISM. An order issued under Section 39.603 or 39.604 must include a mechanism requiring that default charges be reviewed and adjusted at least annually, not later than the 45th day after the anniversary date of the issuance of the order, to:

(1) correct over-collections or under-collections over the preceding 12 months; and

(2) ensure the expected recovery of amounts sufficient to timely provide all payments of debt service.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.607. TAX EXEMPTION. The transfer and receipt of default charges are exempt from state and local sales and use, franchise, and gross receipts taxes.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.608. PROPERTY RIGHTS. (a) The rights and interests of the independent organization or its successor under a debt obligation order issued under this subchapter, including the right to impose, collect, and receive default charges, shall be only contract rights until they are first transferred to an assignee or pledged in connection with an investment agreement entered into under Section 404.0241, Government Code, or the issuance of debt obligations, at which time they will become default property, as described by Subsection (b).

(b) Default property shall constitute a present property right for purposes of contracts concerning the sale or pledge of property, even though the imposition and collection of default charges depends on further acts of the independent organization or others that have not yet occurred. A debt obligation order issued under this subchapter shall remain in effect and the property shall continue to exist for the same period as the pledge of the state described by Section 39.609.

(c) All revenues and collections resulting from default charges shall constitute proceeds only of the default property arising from the debt obligation order.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.609. PLEDGE OF STATE. Debt obligations issued pursuant to this subchapter, including any bonds, are not a debt or obligation of the state and are not a charge on its full faith and credit or taxing power. The state pledges, however, for the benefit and protection of financing parties and the independent organization that it will not take or permit any action that would impair the value of default property, or reduce, alter, or impair the default charges to be imposed, collected, and remitted to financing parties, until the principal, interest and premium, and any other charges incurred and contracts to be performed in connection with the related debt obligations have been paid and performed in full. Any party issuing a debt obligation under this subchapter is authorized to include this pledge in any documentation relating to the obligation.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

SUBCHAPTER N. WINTER STORM URI UPLIFT FINANCING

Sec. 39.651. PURPOSE; USE OF PROCEEDS. (a) The purpose of this subchapter is to address the Winter Storm Uri uplift balance by:

(1) enabling the independent organization certified under Section 39.151 for the ERCOT power region to finance the uplift balance on behalf of wholesale market participants through debt obligations; and

(2) authorizing the commission to contract with

another state agency to finance the payment of the uplift balance with debt obligations or use any another financial mechanism consistent with this subchapter for that purpose.

(b) Financing the uplift balance in the manner provided by this subchapter will allow wholesale market participants who were assessed extraordinary uplift charges due to consumption during the period of emergency to pay those charges over a longer period of time, alleviating liquidity issues and reducing the risk of additional defaults in the wholesale market.

(c) The legislature finds that authorizing financing under this subchapter serves the public purpose of allowing the commission to stabilize the wholesale electricity market in the ERCOT power region.

(d) The proceeds of debt obligations issued under this subchapter must be used solely for the purpose of financing reliability deployment price adder charges and ancillary service costs that exceeded the commission's system-wide offer cap and were uplifted to load-serving entities based on consumption during the period of emergency. A load-serving entity that receives proceeds from the debt obligations may use the proceeds solely for the purposes of fulfilling payment obligations directly related to such costs and refunding such costs to retail customers who have paid or otherwise would be obligated to pay such costs.

(e) The commission shall ensure that the structuring and pricing of the debt obligations results in the lowest uplift charges consistent with market conditions and the terms of the order issued under this subchapter. The present value calculation must use a discount rate equal to the proposed interest rate on the debt obligations.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.652. DEFINITIONS. In this subchapter:

(1) "Independent organization" means the independent organization certified under Section 39.151 for the ERCOT power region.

(2) "Load-serving entity" means a municipally owned

utility, an electric cooperative, or a retail electric provider.

(3) "Period of emergency" means the period beginning 12:01 a.m., February 12, 2021, and ending 11:59 p.m., February 20, 2021.

(4) "Uplift balance" means an amount of money of not more than $2.1 billion that was uplifted to load-serving entities on a load ratio share basis due to energy consumption during the period of emergency for reliability deployment price adder charges and ancillary services costs in excess of the commission's system-wide offer cap, excluding amounts securitized under Subchapter D, Chapter 41. The term does not include amounts that were part of the prevailing settlement point price during the period of emergency.

(5) "Uplift charges" means charges assessed to load-serving entities to repay amounts financed under this subchapter to pay the uplift balance and reasonable costs incurred by a state agency or the independent organization to implement a debt obligation order under Section 39.653, 39.654, or 39.655, including the cost of retiring or refunding existing debt.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.653. DEBT OBLIGATION ORDER. (a) The independent organization shall file an application with the commission to establish a debt financing mechanism for the payment of the uplift balance if the commission finds that such financing will support the financial integrity of the wholesale market and is necessary to protect the public interest, considering the impacts on both wholesale market participants and retail customers.

(b) An order issued under this section must:

(1) state the uplift balance to be financed;

(2) state the period over which the uplift charges must be assessed to repay the debt obligations, which may not exceed 30 years; and

(3) provide the process for remitting the proceeds of the financing to load-serving entities who were exposed to the costs included in the uplift balance, including a requirement for

the load-serving entities to submit documentation of their exposure.

(c) The independent organization shall assess uplift charges to all load-serving entities on a load ratio share basis, which may be translated to a kWh charge, including load serving entities who enter the market after an order has been issued under this subchapter, but excluding the load of entities that opt out under Subsection (d).

(d) The commission shall develop a one-time process that allows municipally owned utilities, electric cooperatives, river authorities, a retail electric provider that has the same corporate parent as each of the provider's customers, a retail electric provider that is an affiliate of each of the provider's customers, and transmission-voltage customers served by a retail electric provider to opt out of the uplift charges by paying in full all invoices owed for usage during the period of emergency. Load-serving entities and transmission-voltage customers that opt out under this subsection shall not receive any proceeds from the uplift financing.

(e) An order issued under this section must include a requirement that any load-serving entity that receives proceeds from the financing that exceed the entity's actual exposure to uplift charges from consumption during the period of emergency notify the independent organization and remit any excess receipts. Any payments received under this subsection must be credited against the uplift balance to reduce the remaining uplift charges.

(f) Not later than the 90th day after the date the independent organization files an application for an order under Subsection (a), the commission shall issue an order described by Subsection (a) or an order denying the application. The order becomes effective in accordance with its terms and the order, together with the uplift charges authorized in the order, shall be irrevocable and not subject to reduction, impairment, or adjustment by further action of the commission after it takes effect. Notwithstanding this requirement, the commission may refinance any debt obligations created by an order under this subchapter if the commission determines that the refinancing is in the public interest and otherwise meets the requirements of this subchapter.

(g) An order issued under this section is not subject to rehearing by the commission. An order may be reviewed by appeal by a party to the proceeding to a Travis County district court filed not later than the 15th day after the date the order is signed by the commission. The judgment of the district court may be reviewed only by direct appeal to the Supreme Court of Texas filed not later than the 15th day after the date of the entry of judgment. All appeals shall be heard and determined by the district court and the Supreme Court of Texas as expeditiously as possible with lawful precedence over other matters. Review on appeal shall be based solely on the record before the commission and briefs to the court and shall be limited to whether the order conforms to the constitution and laws of this state and the United States and is within the authority of the commission under this chapter.

(h) A debt obligation issued under this section is a nonrecourse debt secured solely by the uplift charges explicitly assessed to repay the obligation. The independent organization's obligations authorized under this section do not create personal liability for the independent organization.

(i) This section does not apply to any balance securitized under Subchapter D, Chapter 41.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.654. COMMISSION-AUTHORIZED FINANCING. (a) The commission may contract with another state agency with expertise in public financing to establish a debt financing mechanism to finance the payment of the uplift balance under an order that meets the requirements of Section 39.653.

(b) The contracted state agency and any issuer must be a party to the commission's proceedings that address the issuance of an order along with the independent organization.

(c) In addition to the other applicable requirements of this subtitle, an order issued under this section must:

(1) require the sale, assignment, or other transfer to the contracted state agency of uplift charges created by the order and, following that sale, assignment, or transfer, require that uplift charges paid under any order be created, assessed, and collected as the property of the contracted state agency, subject to subsequent sale, assignment, or transfer by the contracted state agency as authorized under this subchapter;

(2) authorize:

(A) the issuance of debt obligations by the contracted state agency secured by a pledge of uplift charge revenue, and the application of the proceeds of those debt obligations, net of issuance costs, to the independent organization; or

(B) the acquisition of uplift charge revenue from the independent organization by the contracted state agency, financed:

(i) by a loan by an issuer to the contracted state agency of the proceeds of debt obligations, net of issuance costs; or

(ii) by the acquisition by an issuer from the contracted state agency of the uplift charge revenue and in each case the pledge of the revenue to the repayment of the loan or debt obligations, as applicable; and

(3) authorize the independent organization to serve as collection agent to collect the uplift charges and transfer the collected uplift charges to the contracted state agency or the issuer, as appropriate.

(d) After issuance of the order, the contracted state agency shall arrange for the issuance of debt obligations, as specified by the order, by the contracted state agency or another issuer selected by the contracted state agency and approved by the commission.

(e) Debt obligations issued pursuant to an order issued under this section are secured only by the uplift charge revenue and any other funds pledged under the bond documents. No assets of the state or the independent organization are subject to claims by the holders of the debt obligations. Following assignment of the uplift charge revenue, the independent organization does not have any beneficial interest or claim of right in the revenue.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.655. OTHER FINANCIAL MECHANISM. The commission may use a financial mechanism other than the mechanisms described by Sections 39.653 and 39.654 that meets the requirements of this subchapter to accomplish the purposes of this subchapter.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.656. UPLIFT CHARGES NONBYPASSABLE. An order issued under Section 39.653, 39.654, or 39.655 must:

(1) include terms ensuring that the imposition and collection of uplift charges authorized in the order shall be nonbypassable, except for entities excluded under Section 39.653(d); and

(2) authorize the independent organization to establish appropriate fees and other methods for pursuing amounts owed from entities exiting the wholesale market.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.657. TRUE-UP. An order shall include a mechanism requiring that uplift charges be reviewed and adjusted at least annually, not later than the 45th day after the anniversary date of the issuance of the debt obligations, to:

(1) correct over-collections or under-collections over the preceding 12 months; and

(2) 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 debt obligations.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.658. TAX EXEMPTION. Transactions involving the transfer and ownership of uplift property and the receipt of uplift charges are exempt from state and local income, sales, franchise, gross receipts, and other taxes or similar charges.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.659. SEVERABILITY. Effective on the date the first debt obligations are issued under this subchapter, if any provision in this title or portion of this title is held to be invalid or is invalidated, superseded, replaced, repealed, or expires for any reason, that occurrence does not affect the validity or continuation of this subchapter or any other provision of this title that is relevant to the issuance, administration, payment, retirement, or refunding of debt obligations or to any actions of the independent organization, its successors, an assignee, a collection agent, or a financing party, which shall remain in full force and effect.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.660. CUSTOMER CHARGES. All load-serving entities that receive offsets to specific uplift charges from the independent organization under this subchapter must adjust customer invoices to reflect the offsets for any charges that were or would otherwise be passed through to customers under the terms of service with the load-serving entity, including by providing a refund for any offset charges that were previously paid. An electric cooperative, including an electric cooperative that elects to receive offsets, shall not otherwise become subject to rate regulation by the commission and receipt of offsets does not affect the applicability of Chapter 41 to an electric cooperative.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.661. ENFORCEMENT. The commission may use any enforcement mechanism established by Chapter 15 or this chapter, including revocation of certification by the commission, against any entity that fails to remit excess receipts from the uplift balance financing under Section 39.653(e) or otherwise misappropriates or misuses amounts received from the uplift balance financing this subchapter.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.662. PROPERTY RIGHTS. (a) The rights and interests of the independent organization or its successor under a debt obligation order issued under this subchapter, including the right to impose, collect, and receive uplift charges authorized in a debt obligation order under this subchapter, shall be only contract rights until they are first transferred to an assignee or pledged in connection with the issuance of a financing agreement entered into under Section 39.654(a) or the issuance of debt obligations, at which time they will become uplift property, as described by Subsection (b).

(b) Uplift property shall constitute a present property right for purposes of contracts concerning the sale or pledge of property, even though the imposition and collection of uplift charges depends on further acts of the independent organization or others that have not yet occurred. A debt obligation order issued under this subchapter shall remain in effect and the property shall continue to exist for the same period as the pledge of the state described by Section 39.663.

(c) All revenues and collections resulting from uplift charges shall constitute proceeds only of the uplift property arising from the debt obligation order.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.663. PLEDGE OF STATE. Debt obligations issued pursuant to this subchapter, including any bonds, are not a debt or obligation of the state and are not a charge on its full faith and credit or taxing power. The state pledges, however, for the benefit and protection of financing parties and the independent organization that it will not take or permit any action that would impair the value of uplift property, or reduce, alter, or impair the uplift charges to be imposed, collected, and remitted to financing parties, until the principal, interest and premium, and any other charges incurred and contracts to be performed in connection with the related debt obligations have been paid and performed in full. Any party issuing a debt obligation under this subchapter is authorized to include this pledge in any documentation relating to the obligation.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

Sec. 39.664. LEGAL ACTIONS INVOLVING PRICING OR UPLIFT ACTIONS. A load-serving entity that receives proceeds from the financing under this subchapter shall return an amount of the proceeds equal to any amount of money received by the entity due to litigation seeking judicial review of pricing or uplift actions taken by the commission or the independent organization in connection with the period of emergency.

Added by Acts 2021, 87th Leg., R.S., Ch. 908 (H.B. 4492), Sec. 5, eff. June 16, 2021.

SUBCHAPTER Z. MISCELLANEOUS PROVISIONS

Sec. 39.9016. NUCLEAR SAFETY FEE. An electric utility that operates a nuclear asset located in a county on the coast of the Gulf of Mexico shall pay a nuclear safety fee for the year 2000 and the year 2001 to each taxing unit in which the nuclear asset is located, other than a school district, in an amount equal to the difference between the ad valorem taxes imposed by the taxing unit in 1999 and the amount of ad valorem taxes imposed by the unit in the year for which the fee is due, except that the amount of the fee may not exceed one-half the taxes imposed on the asset by the unit in 1999. The nuclear safety fee shall be considered a tax or fee under Section 39.258(5).

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.902. CUSTOMER EDUCATION. (a) On or before January

1, 2001, the commission shall develop and implement an educational program to inform customers, including low-income and non-English-speaking customers, about changes in the provision of electric service resulting from the opening of the retail electric market and the customer choice pilot program under this chapter. The educational program shall be neutral and nonpromotional and shall provide customers with the information necessary to make informed decisions relating to the source and type of electric service available for purchase and other information the commission considers necessary. The educational program shall inform customers of their rights and of the protections available through the commission and the office. The educational program may not duplicate customer information efforts undertaken by retail electric providers or other private entities. The educational program may not be targeted to areas served by municipally owned utilities or electric cooperatives that have not adopted customer choice. In planning and implementing this program, the commission shall consult with the office, with the Texas Department of Housing and Community Affairs, and with customers of and providers of retail electric service. The commission may enter into contracts for professional services to carry out the customer education program.

(b) Repealed by Acts 2011, 82nd Leg., R.S., Ch. 1083, Sec. 25(162), eff. June 17, 2011.

(c) After the opening of the retail electric market, the commission shall conduct ongoing customer education designed to help customers make informed choices of electric services and retail electric providers. As part of ongoing education, the commission may provide customers information concerning specific retail electric providers, including instances of complaints against them and records relating to quality of customer service.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.
Amended by:

Acts 2011, 82nd Leg., R.S., Ch. 1083 (S.B. 1179), Sec. 25(162), eff. June 17, 2011.

Sec. 39.9025. HOME ELECTRIC ENERGY REPORTS. The commission may encourage retail electric providers to deliver individualized home electric energy reports to educate consumers about electric energy use and energy efficiency to assist consumers to use energy more efficiently.

Added by Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 21, eff. September 1, 2007.

This section expired September 1, 2017, according to the date provided by Subsection (m).

Sec. 39.903. SYSTEM BENEFIT FUND. (a) The system benefit fund is an account in the general revenue fund. Money in the account may be appropriated only for the purposes provided by this section or other law. Interest earned on the system benefit fund shall be credited to the fund. Section 403.095, Government Code, does not apply to the system benefit fund.

(b) The system benefit fund is financed by a nonbypassable fee set by the commission in an amount not to exceed 65 cents per megawatt hour. The system benefit fund fee is allocated to customers based on the amount of kilowatt hours used.

(c) The nonbypassable fee may not be imposed on the retail electric customers of a municipally owned utility or electric cooperative before the sixth month preceding the date on which the utility or cooperative implements customer choice. Money distributed from the system benefit fund to a municipally owned utility or an electric cooperative shall be proportional to the nonbypassable fee paid by the municipally owned utility or the electric cooperative, subject to the reimbursement provided by Subsection (i). On request by a municipally owned utility or electric cooperative, the commission shall reduce the nonbypassable fee imposed on retail electric customers served by the municipally owned utility or electric cooperative by an amount equal to the amount provided by the municipally owned utility or electric cooperative or its ratepayers for local low-income programs and local programs that educate customers about the retail electric market in a neutral and nonpromotional manner.

(d) The commission shall annually review and approve system benefit fund accounts, projected revenue requirements, and proposed nonbypassable fees.

(e) Money in the system benefit fund may be appropriated to provide funding solely for the following regulatory purposes, in the following order of priority:

(1) programs to:

(A) assist low-income electric customers by providing the 10 percent reduced rate prescribed by Subsection (h); and

(B) provide one-time bill payment assistance to electric customers who are or who have in their households one or more seriously ill or disabled low-income persons and who have been threatened with disconnection for nonpayment;

(2) customer education programs, administrative expenses incurred by the commission in implementing and administering this chapter, and expenses incurred by the office under this chapter;

(3) programs to assist low-income electric customers by providing the targeted energy efficiency programs described by Subsection (f)(2);

(4) programs to assist low-income electric customers by providing the 20 percent reduced rate prescribed by Subsection (h); and

(5) reimbursement to the commission and the Health and Human Services Commission for expenses incurred in the implementation and administration of an integrated eligibility process created under Section 17.007 for customer service discounts relating to retail electric service, including outreach expenses the commission determines are reasonable and necessary.

(f) Notwithstanding Section 39.106(b), the commission shall adopt rules regarding programs to assist low-income electric customers on the introduction of customer choice. The programs may not be targeted to areas served by municipally owned utilities or electric cooperatives that have not adopted customer choice. The programs shall include:

(1) reduced electric rates as provided by Subsections (h)-(l); and

(2) targeted energy efficiency programs to be

administered by the Texas Department of Housing and Community Affairs in coordination with existing weatherization programs.

(g) Until customer choice is introduced in a power region, an electric utility may not reduce, in any manner, programs already offered to assist low-income electric customers.

(h) The commission shall adopt rules for a retail electric provider to determine a reduced rate for eligible customers to be discounted off the standard retail service package as approved by the commission under Section 39.106, or the price to beat established by Section 39.202, whichever is lower. Municipally owned utilities and electric cooperatives shall establish a reduced rate for eligible customers to be discounted off the standard retail service package established under Section 40.053 or 41.053, as appropriate. The reduced rate for a retail electric provider shall result in a total charge that is at least 10 percent and, if sufficient money in the system benefit fund is available, up to 20 percent, lower than the amount the customer would otherwise be charged. To the extent the system benefit fund is insufficient to fund the initial 10 percent rate reduction, the commission may increase the fee to an amount not more than 65 cents per megawatt hour, as provided by Subsection (b). If the fee is set at 65 cents per megawatt hour or if the commission determines that appropriations are insufficient to fund the 10 percent rate reduction, the commission may reduce the rate reduction to less than 10 percent. For a municipally owned utility or electric cooperative, the reduced rate shall be equal to an amount that can be fully funded by that portion of the nonbypassable fee proceeds paid by the municipally owned utility or electric cooperative that is allocated to the utility or cooperative by the commission under Subsection (e) for programs for low-income customers of the utility or cooperative. The reduced rate for municipally owned utilities and electric cooperatives under this section is in addition to any rate reduction that may result from local programs for low-income customers of the municipally owned utilities or electric cooperatives.

(i) A retail electric provider, municipally owned utility, or electric cooperative seeking reimbursement from the system benefit fund may not charge an eligible low-income customer a rate higher than the appropriate rate determined under Subsection (h). A retail electric provider not subject to the price to beat, or a municipally owned utility or electric cooperative subject to the nonbypassable fee under Subsection (c), shall be reimbursed from the system benefit fund for the difference between the reduced rate and the rate established under Section 39.106 or, as appropriate, the rate established under Section 40.053 or 41.053. A retail electric provider who is subject to the price to beat shall be reimbursed from the system benefit fund for the difference between the reduced rate and the price to beat. The commission shall adopt rules providing for the reimbursement.

(j) The commission shall adopt rules providing for methods of enrolling customers eligible to receive reduced rates under Subsection (h). The rules must provide for automatic enrollment as one enrollment option. The Texas Department of Human Services, on request of the commission, shall assist in the adoption and implementation of these rules. The commission and the Texas Department of Human Services shall enter into a memorandum of understanding establishing the respective duties of the commission and the department in relation to the automatic enrollment.

(j-1) The commission shall adopt rules governing the bill payment assistance program provided under Subsection (e)(1)(B). The rules must provide that a customer is eligible to receive the assistance only if the assistance is necessary to prevent the disconnection of service for nonpayment of bills and the electric customer is or has in the customer's household one or more seriously ill or disabled low-income persons whose health or safety may be injured by the disconnection. The commission may prescribe the documentation necessary to demonstrate eligibility for the assistance and may establish additional eligibility criteria. The Health and Human Services Commission, on request of the commission, shall assist in the adoption and implementation of these rules.

(k) A retail electric provider is prohibited from charging the customer a fee for participation in the reduced rate program.

(l) For the purposes of this section, a "low-income electric customer" is an electric customer:

(1) whose household income is not more than 125 percent of the federal poverty guidelines; or

(2) who receives food stamps from the Texas Department of Human Services or medical assistance from a state agency administering a part of the medical assistance program.

(m) This section expires September 1, 2017.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999. Amended by Acts 2001, 77th Leg., ch. 1466, Sec. 19(a), eff. June 15, 2001; Acts 2001, 77th Leg., ch. 1394, Sec. 3, eff. Sept. 1, 2001; Acts 2001, 77th Leg., ch. 1451, Sec. 3, eff. Sept. 1, 2001; Acts 2003, 78th Leg., ch. 211, Sec. 2.02, eff. June 16, 2003; Acts 2003, 78th Leg., ch. 1296, Sec. 4(a), eff. June 20, 2003.

Amended by:

Acts 2005, 79th Leg., Ch. 412 (S.B. 1652), Sec. 17, eff. September 1, 2005.

Acts 2005, 79th Leg., Ch. 728 (H.B. 2018), Sec. 21.001, eff. September 1, 2005.

Acts 2005, 79th Leg., Ch. 797 (S.B. 408), Sec. 11, eff. September 1, 2005.

Acts 2005, 79th Leg., Ch. 797 (S.B. 408), Sec. 12, eff. September 1, 2005.

Acts 2005, 79th Leg., Ch. 899 (S.B. 1863), Sec. 14.01, eff. August 29, 2005.

Acts 2013, 83rd Leg., R.S., Ch. 170 (H.B. 1600), Sec. 1.10, eff. September 1, 2013.

Acts 2013, 83rd Leg., R.S., Ch. 835 (H.B. 7), Sec. 16, eff. June 14, 2013.

Acts 2015, 84th Leg., R.S., Ch. 706 (H.B. 1101), Sec. 1, eff. June 17, 2015.

Sec. 39.9044. GOAL FOR NATURAL GAS. (a) It is the intent of the legislature that 50 percent of the megawatts of generating capacity installed in this state after January 1, 2000, use natural gas. To the extent permitted by law, the commission shall establish a program to encourage utilities to comply with this section by using natural gas produced in this state as the preferential fuel.

This section does not apply to generating capacity for renewable energy technologies.

(b) The commission shall establish a natural gas energy credits trading program. Any power generation company, municipally owned utility, or electric cooperative that does not satisfy the requirements of Subsection (a) by directly owning or purchasing capacity using natural gas technologies shall purchase sufficient natural gas energy credits to satisfy the requirements by holding natural gas energy credits in lieu of capacity from natural gas energy technologies.

(c) Not later than January 1, 2000, the commission shall adopt rules necessary to administer and enforce this section and to perform any necessary studies in cooperation with the Railroad Commission of Texas. At a minimum, the rules shall:

(1) establish the minimum annual natural gas generation requirement for each power generation company, municipally owned utility, and electric cooperative operating in this state in a manner reasonably calculated by the commission to produce, on a statewide basis, compliance with the requirement prescribed by Subsection (a); and

(2) specify reasonable performance standards that all natural gas capacity additions must meet to count against the requirement prescribed by Subsection (a) and that:

(A) are designed and operated so as to maximize the energy output from the capacity additions in accordance with then-current industry standards and best industry standards; and

(B) encourage the development, construction, and operation of new natural gas energy projects at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial natural gas resources.

(d) The commission, with the assistance of the Railroad Commission of Texas, shall adopt rules allowing and encouraging retail electric providers and municipally owned utilities and electric cooperatives that have adopted customer choice to market electricity generated using natural gas produced in this state as environmentally beneficial. The rules shall allow a provider, municipally owned utility, or cooperative to:

(1) emphasize that natural gas produced in this state is the cleanest-burning fossil fuel; and

(2) label the electricity generated using natural gas produced in this state as "green" electricity.

(e) In this section, "natural gas technology" means any technology that exclusively relies on natural gas as a primary fuel source.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.9048. NATURAL GAS FUEL. It is the intent of the legislature that:

(1) the cost of generating electricity remain as low as possible; and

(2) the state establish and publicize a program to keep the costs of fuel, such as natural gas, used for generating electricity low.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.905. GOAL FOR ENERGY EFFICIENCY. (a) It is the goal of the legislature that:

(1) electric utilities will administer energy efficiency incentive programs in a market-neutral, nondiscriminatory manner but will not offer underlying competitive services;

(2) all customers, in all customer classes, will have a choice of and access to energy efficiency alternatives and other choices from the market that allow each customer to reduce energy consumption, summer and winter peak demand, or energy costs;

(3) each electric utility annually will provide, through market-based standard offer programs or through targeted market-transformation programs, incentives sufficient for retail electric providers and competitive energy service providers to acquire additional cost-effective energy efficiency, subject to cost ceilings established by the commission, for the utility's residential and commercial customers equivalent to:

(A) not less than:

(i) 30 percent of the electric utility's annual growth in demand of residential and commercial customers by December 31 of each year beginning with the 2013 calendar year; and

(ii) the amount of energy efficiency to be acquired for the utility's residential and commercial customers for the most recent preceding year; and

(B) for an electric utility whose amount of energy efficiency to be acquired under this subsection is equivalent to at least four-tenths of one percent of the electric utility's summer weather-adjusted peak demand for residential and commercial customers in the previous calendar year, not less than:

(i) four-tenths of one percent of the utility's summer weather-adjusted peak demand for residential and commercial customers by December 31 of each subsequent year; and

(ii) the amount of energy efficiency to be acquired for the utility's residential and commercial customers for the most recent preceding year;

(4) each electric utility in the ERCOT region shall use its best efforts to encourage and facilitate the involvement of the region's retail electric providers in the delivery of efficiency programs and demand response programs under this section, including programs for demand-side renewable energy systems that:

(A) use distributed renewable generation, as defined by Section 39.916; or

(B) reduce the need for energy consumption by using a renewable energy technology, a geothermal heat pump, a solar water heater, or another natural mechanism of the environment;

(5) retail electric providers in the ERCOT region, and electric utilities outside of the ERCOT region, shall provide customers with energy efficiency educational materials; and

(6) notwithstanding Subsection (a)(3), electric utilities shall continue to make available, at 2007 funding and participation levels, any load management standard offer programs developed for industrial customers and implemented prior to May 1, 2007.

(b) The commission shall provide oversight and adopt rules and procedures to ensure that the utilities can achieve the goal of this section, including:

(1) establishing an energy efficiency cost recovery factor for ensuring timely and reasonable cost recovery for utility expenditures made to satisfy the goal of this section;

(2) establishing an incentive under Section 36.204 to reward utilities administering programs under this section that exceed the minimum goals established by this section;

(3) providing a utility that is unable to establish an energy efficiency cost recovery factor in a timely manner due to a rate freeze with a mechanism to enable the utility to:

(A) defer the costs of complying with this section; and

(B) recover the deferred costs through an energy efficiency cost recovery factor on the expiration of the rate freeze period;

(4) ensuring that the costs associated with programs provided under this section and any shareholder bonus awarded are borne by the customer classes that receive the services under the programs;

(5) ensuring the program rules encourage the value of the incentives to be passed on to the end-use customer;

(6) ensuring that programs are evaluated, measured, and verified using a framework established by the commission that promotes effective program design and consistent and streamlined reporting; and

(7) ensuring that an independent organization certified under Section 39.151 allows load participation in all energy markets for residential, commercial, and industrial customer classes, either directly or through aggregators of retail customers, to the extent that load participation by each of those customer classes complies with reasonable requirements adopted by the organization relating to the reliability and adequacy of the regional electric network and in a manner that will increase market efficiency, competition, and customer benefits.

(b-1) The energy efficiency cost recovery factor under

Subsection (b)(1) may not result in an over-recovery of costs but may be adjusted each year to change rates to enable utilities to match revenues against energy efficiency costs and any incentives to which they are granted. The factor shall be adjusted to reflect any over-collection or under-collection of energy efficiency cost recovery revenues in previous years.

(b-2) Repealed by Acts 2011, 82nd Leg., R.S., Ch. 180, Sec. 3, eff. September 1, 2011.

(b-3) Beginning not later than January 1, 2008, the commission, in consultation with the State Energy Conservation Office, annually for a period of five years shall compute and report to ERCOT the projected energy savings and demand impacts for each entity in the ERCOT region that administers standard offer programs, market transformation programs, combined heating and power technology, demand response programs, solar incentive programs, appliance efficiency standards, energy efficiency programs in public buildings, and any other relevant programs that are reasonably anticipated to reduce electricity energy or peak demand or that serve as substitutes for electric supply.

(b-4) The commission and ERCOT shall develop a method to account for the projected efficiency impacts under Subsection (b-3) in ERCOT's annual forecasts of future capacity, demand, and reserves.

(c) A standard offer program provided under Subsection (a)(3) must be neutral with respect to technologies, equipment, and fuels, including thermal, chemical, mechanical, and electrical energy storage technologies.

(d) The commission shall establish a procedure for reviewing and evaluating market-transformation program options described by this subsection and other options. In evaluating program options, the commission may consider the ability of a program option to reduce costs to customers through reduced demand, energy savings, and relief of congestion. Utilities may choose to implement any program option approved by the commission after its evaluation in order to satisfy the goal in Subsection (a), including:

(1) energy-smart schools;

(2) appliance retirement and recycling;

(3) air conditioning system tune-ups;

(4) the installation of variable speed air conditioning systems, motors, and drives;

(5) the use of trees or other landscaping for energy efficiency;

(6) customer energy management and demand response programs;

(7) high performance residential and commercial buildings that will achieve the levels of energy efficiency sufficient to qualify those buildings for federal tax incentives;

(8) commissioning services for commercial and institutional buildings that result in operational and maintenance practices that reduce the buildings' energy consumption;

(9) programs for customers who rent or lease their residence or commercial space;

(10) programs providing energy monitoring equipment to customers that enable a customer to better understand the amount, price, and time of the customer's energy use;

(11) energy audit programs for owners and other residents of single-family or multifamily residences and for small commercial customers;

(12) net-zero energy new home programs;

(13) solar thermal or solar electric programs;

(14) programs for using windows and other glazing systems, glass doors, and skylights in residential and commercial buildings that reduce solar gain by at least 30 percent from the level established for the federal Energy Star windows program;

(15) data center efficiency programs; and

(16) energy use programs with measurable and verifiable results that reduce energy consumption through behavioral changes that lead to efficient use patterns and practices.

(e) An electric utility may use money approved by the commission for energy efficiency programs to perform necessary energy efficiency research and development to foster continuous improvement and innovation in the application of energy efficiency technology and energy efficiency program design and implementation. Money the utility uses under this subsection may not exceed 10 percent of the greater of:

(1) the amount the commission approved for energy efficiency programs in the utility's most recent full rate proceeding; or

(2) the commission-approved expenditures by the utility for energy efficiency in the previous year.

(f) Each unbundled transmission and distribution utility shall include in its energy efficiency plan a targeted low-income energy efficiency program, and the savings achieved by the program shall count toward the transmission and distribution utility's energy efficiency goal. The commission shall determine the appropriate level of funding to be allocated to both targeted and standard offer low-income energy efficiency programs in each unbundled transmission and distribution utility service area. The level of funding for low-income energy efficiency programs shall be provided from money approved by the commission for the transmission and distribution utility's energy efficiency programs. The commission shall ensure that annual expenditures for the targeted low-income energy efficiency programs of each unbundled transmission and distribution utility are not less than 10 percent of the transmission and distribution utility's energy efficiency budget for the year. A targeted low-income energy efficiency program must comply with the same audit requirements that apply to federal weatherization subrecipients. In an energy efficiency cost recovery factor proceeding related to expenditures under this subsection, the commission shall make findings of fact regarding whether the utility meets requirements imposed under this subsection. The state agency that administers the federal weatherization assistance program shall participate in energy efficiency cost recovery factor proceedings related to expenditures under this subsection to ensure that targeted low-income weatherization programs are consistent with federal weatherization programs and adequately funded.

(g) The commission may provide for a good cause exemption to a utility's liability for an administrative penalty or other sanction if the utility fails to meet a goal for energy efficiency under this section and the utility's failure to meet the goal is caused by one or more factors outside of the utility's control, including:

(1) insufficient demand by retail electric providers and competitive energy 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.

(h) For an electric utility operating in an area not open to competition, the utility may achieve the goal of this section by:

(1) providing rebate or incentive funds directly to customers to promote or facilitate the success of programs implemented under this section; or

(2) 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 requirements as standard offer programs and market transformation programs.

(i) For an electric utility operating in an area open to competition, on demonstration to the commission, after a contested case hearing, that the requirements under Subsection (a) cannot be met in a rural area through retail electric providers or competitive energy service providers, the utility may achieve the goal of this section by providing rebate or incentive funds directly to customers in the rural area to promote or facilitate the success of programs implemented under this section.

(j) An electric utility may use energy audit programs to achieve the goal of this section if:

(1) the programs do not constitute more than three percent of total program costs under this section; and

(2) the addition of the programs does not cause a utility's portfolio of programs to no longer be cost-effective.

(k) To help a residential or nongovernmental nonprofit customer make informed decisions regarding energy efficiency, the commission may consider program designs that ensure, to the extent practicable, the customer is provided with information using standardized forms and terms that allow the customer to compare offers for varying degrees of energy efficiency attainable using a measure the customer is considering by cost, estimated energy savings, and payback periods.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2005, 79th Leg., Ch. 328 (S.B. 712), Sec. 1, eff. September 1, 2005.

Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 22, eff. September 1, 2007.

Acts 2011, 82nd Leg., R.S., Ch. 180 (S.B. 1125), Sec. 1, eff. September 1, 2011.

Acts 2011, 82nd Leg., R.S., Ch. 180 (S.B. 1125), Sec. 3, eff. September 1, 2011.

Acts 2011, 82nd Leg., R.S., Ch. 1346 (S.B. 1434), Sec. 1, eff. June 17, 2011.

Acts 2013, 83rd Leg., R.S., Ch. 1079 (H.B. 3361), Sec. 4.01, eff. September 1, 2013.

Acts 2019, 86th Leg., R.S., Ch. 467 (H.B. 4170), Sec. 16.003, eff. September 1, 2019.

Sec. 39.9051. ENERGY EFFICIENCY FOR MUNICIPALLY OWNED UTILITIES. (a) In this section, "municipally owned utility" has the meaning assigned by Section 11.003.

(b) This section applies only to a municipally owned utility that had retail sales of more than 500,000 megawatt hours in 2005.

(c) It is the goal of the legislature that:

(1) municipally owned utilities will administer energy savings incentive programs;

(2) customers of a municipally owned utility will have a choice of and access to energy efficiency alternatives that allow customers to reduce energy consumption, peak demand, or energy costs; and

(3) each municipally owned utility will provide incentives sufficient for municipally owned utilities to acquire additional cost-effective energy efficiency.

(d) The governing body of a municipally owned utility shall provide oversight and adopt rules and procedures, as necessary, to ensure that the utility can achieve the goal of this section.

(e) If a municipally owned utility adopts customer choice by decision of the governing body under Chapter 40, the commission shall provide oversight and adopt rules and procedures, as necessary, to ensure that the municipally owned utility can achieve the goal in this section in a market-neutral, nondiscriminatory manner. The commission shall, to the extent possible, include existing energy efficiency programs already adopted by the municipally owned utility.

(f) Beginning April 1, 2012, a municipally owned utility must report each year to the State Energy Conservation Office, on a standardized form developed by the office, information regarding the combined effects of the energy efficiency activities of the utility from the previous calendar year, including the utility's annual goals, programs enacted to achieve those goals, and any achieved energy demand or savings goals.

(g) The State Energy Conservation Office shall provide the reports made under Subsection (f) to the Energy Systems Laboratory at the Texas Engineering Experiment Station of The Texas A&M University System. The laboratory shall calculate the energy savings and estimated pollution reductions that resulted from the reported activities.

(h) The energy systems laboratory shall share the results of the analysis with the Public Utility Commission of Texas, ERCOT, the United States Environmental Protection Agency, and the Texas Commission on Environmental Quality.

Added by Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 23, eff. September 1, 2007.

Amended by:

Acts 2011, 82nd Leg., R.S., Ch. 1068 (S.B. 924), Sec. 1, eff. September 1, 2011.

Sec. 39.9052. ENERGY EFFICIENCY FOR ELECTRIC COOPERATIVES. (a) An electric cooperative shall consider adopting and implementing energy efficiency programs that reduce the cooperative's annual growth in demand in a manner consistent with standards established in the state for other utilities.

(b) Beginning April 1, 2012, an electric cooperative that had retail sales of more than 500,000 megawatt hours in 2005 must report each year to the State Energy Conservation Office, on a standardized form developed by the office, information regarding the combined effects of the energy efficiency activities of the electric cooperative from the previous calendar year, including the electric cooperative's annual goals, programs enacted to achieve those goals, and any achieved energy demand or savings goals.

(c) The State Energy Conservation Office shall provide the reports made under Subsection (b) to the Energy Systems Laboratory at the Texas Engineering Experiment Station of The Texas A&M University System. The laboratory shall calculate the energy savings and estimated pollution reductions that resulted from the reported activities.

(d) The energy systems laboratory shall share the results of the analysis with the Public Utility Commission of Texas, ERCOT, the United States Environmental Protection Agency, and the Texas Commission on Environmental Quality.

Added by Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 23, eff. September 1, 2007.

Amended by:

Acts 2011, 82nd Leg., R.S., Ch. 1068 (S.B. 924), Sec. 2, eff. September 1, 2011.

Sec. 39.9054. ENERGY EFFICIENCY PLANS AND REPORTS; PUBLIC INFORMATION. (a) An electric utility shall submit electronically an energy efficiency plan and report in a searchable form prescribed by the commission on or before April 1 of each year. The commission by rule shall adopt a form that will permit the public to easily compare information submitted by different electric utilities. The plan and report must:

(1) provide information on the utility's performance in achieving energy efficiency goals for the previous five years;

(2) describe how the utility intends to achieve future goals; and

(3) provide any other information the commission considers relevant.

(b) On the Internet website found at http://www.puc.state.tx.us, the commission shall publish information on energy efficiency programs, including:

(1) an explanation of the goal for energy efficiency in this state;

(2) a description of the types of energy efficiency programs available to certain classes of eligible customers;

(3) a link to the plans and reports filed as prescribed by Subsection (a); and

(4) a list of persons who install or provide energy efficiency measures or services by area.

(c) This section does not require the commission to warrant that the list required to be displayed under Subsection (b) constitutes a complete or accurate list of all persons who install energy efficiency measures or services in the marketplace.

Added by Acts 2011, 82nd Leg., R.S., Ch. 180 (S.B. 1125), Sec. 2, eff. September 1, 2011.

Sec. 39.9055. EXAMINATION OF DEMAND RESPONSE POTENTIAL OF SEAWATER DESALINATION PROJECTS. The commission and the ERCOT independent system operator shall study the potential for seawater desalination projects to participate in existing demand response opportunities in the ERCOT market. To the extent feasible, the study shall determine whether the operational characteristics of seawater desalination projects enable projects of that kind to participate in ERCOT-operated ancillary services markets or other competitively supplied demand response opportunities. The study shall also determine the potential economic benefit to a seawater desalination project if the project is able to reduce its demand during peak pricing periods. The commission shall include the results of the study in the report required by Section 12.203.

Added by Acts 2015, 84th Leg., R.S., Ch. 829 (H.B. 4097), Sec. 2, eff. June 17, 2015.

Amended by:

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 35, eff.

September 1, 2023.

Sec. 39.906. DISPLACED WORKERS. In order to mitigate potential negative impacts on utility personnel directly affected by electric industry restructuring, the commission shall allow the recovery of reasonable employee-related transition costs incurred and projected for severance, retraining, early retirement, outplacement, and related expenses for the employees.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Sec. 39.908. EFFECT OF SUNSET PROVISION. If the commission is abolished under Section 12.005 or other law, the authorities, duties, and functions of the commission under this chapter shall be performed and carried out by a successor agency to be designated by the legislature before abolishment of the commission or, if the legislature does not designate the successor, by the secretary of state.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.

Amended by:

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 36, eff. September 1, 2023.

Sec. 39.909. PLAN AND REPORT OF WORKFORCE DIVERSITY AND OTHER BUSINESS PRACTICES. (a) In this section, "small business" and "historically underutilized business" have the meanings assigned by former Section 481.191, Government Code, as that section existed on January 1, 2015.

(b) Before January 1, 2000, each electric utility shall develop and submit to the commission a comprehensive five-year plan to enhance diversity of its workforce in all occupational categories and to increase contracting opportunities for small and historically underutilized businesses. The plan must consist of:

(1) the electric utility's historical and current performance with regard to workforce diversity and contracting with small and historically underutilized businesses;

(2) initiatives that the electric utility will pursue in these areas over the period of the plan;

(3) a listing of programs and activities the electric utility will undertake to achieve each of those initiatives; and

(4) a listing of the business partnership initiatives the electric utility will undertake to facilitate small and historically underutilized business entry into the electric energy market as generators and retail energy providers taking into account opportunities for contracting and joint ventures.

(c) Each electric utility shall submit an annual report to the commission and the legislature relating to its efforts to improve workforce diversity and contracting opportunities for small and historically underutilized businesses. The report must be submitted on October 1 of each year or may be included as part of any other annual report submitted by the electric utility to the commission. The report must include:

(1) the diversity of the electric utility's workforce as of the time of the report;

(2) the electric utility's level of contracting with small and historically underutilized businesses;

(3) the specific progress made under the plan under Subsection (b);

(4) the specific initiatives, programs, and activities undertaken under the plan during the preceding year;

(5) an assessment of the success of each of those initiatives, programs, and activities;

(6) 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; and

(7) 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.

Added by Acts 1999, 76th Leg., ch. 405, Sec. 39, eff. Sept. 1, 1999.
Amended by:

Acts 2015, 84th Leg., R.S., Ch. 364 (H.B. 2667), Sec. 4, eff. September 1, 2015.

Sec. 39.910. INCENTIVE PROGRAM AND GOAL FOR ENERGY EFFICIENCY FOR MILITARY BASES. (a) The commission by rule shall establish an electric energy efficiency incentive program under which each electric utility in an area where customer choice is not available will provide incentives sufficient for military bases, retail electric providers, or competitive energy service providers to install energy efficiency devices or other alternatives at military bases. The commission shall design the program to provide military bases with a variety of choices for cost-effective energy efficiency devices and other alternatives from the market to reduce energy consumption and energy costs.

(b) The commission shall establish a goal for the program to reduce, before January 1, 2005, the consumption of electricity by military bases in this state by five percent as compared to consumption levels in 2002.

(c) The commission shall approve a nonbypassable surcharge or other rate mechanism to recover costs associated with the program established under this section.

(d) An electric utility shall administer the electric energy efficiency incentive program in a market-neutral, nondiscriminatory manner. An electric utility may not offer underlying competitive services.

Added by Acts 2003, 78th Leg., ch. 149, Sec. 23, eff. May 27, 2003.

Sec. 39.911. ALTERNATIVE FUNDING FOR ENERGY EFFICIENCY AND RENEWABLE ENERGY SYSTEMS. The State Energy Conservation Office, in coordination with the governor, the Department of Agriculture, the Texas Commission on Environmental Quality, the Texas Education Agency, the commission, and other appropriate state agencies, shall solicit gifts, grants, and other financial resources available to fund energy efficiency improvements and renewable energy systems for public and private facilities in this state.

Added by Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 23, eff. September 1, 2007.

Sec. 39.9111. RULES RELATED TO RENEWABLE POWER FACILITIES. The commission may adopt rules requiring renewable power facilities to have reactive power control capabilities or any other feasible technology designed to reduce the facilities' effects on system reliability.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 37, eff. September 1, 2023.

Sec. 39.9112. REPORT ON TRANSMISSION AND GENERATION CAPACITY. The commission and the independent organization certified under Section 39.151 for the ERCOT power region shall study the need for increased transmission and generation capacity throughout this state and report to the legislature the results of the study and any recommendations for legislation. The report must be filed with the legislature not later than December 31 of each even-numbered year.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 37, eff. September 1, 2023.

Sec. 39.9113. RENEWABLE ENERGY CREDITS. To facilitate voluntary contractual obligations and verify claims regarding environmental attributes of renewable energy production in this state, the independent organization certified under Section 39.151 for the ERCOT power region shall maintain an accreditation and banking system to award and track voluntary renewable energy credits generated by eligible facilities.

Added by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 37, eff. September 1, 2023.

Sec. 39.912. REPORT ON COMBINED HEATING AND POWER TECHNOLOGY. The commission shall study the installation and use of combined heating and power technology in this state, and shall submit a report regarding the commission's findings to the 81st Legislature. The report shall include:

(1) an explanation describing combined heating and power technology and its use; and

(2) an explanation of how combined heating and power technology can be implemented in this state to meet energy efficiency goals.

Added by Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 23, eff. September 1, 2007.

Sec. 39.913. COMBINING CERTAIN REPORTS. The commission may combine the reports required under Sections 39.905(b-2) and 39.912.
Added by Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 23, eff. September 1, 2007.

Sec. 39.914. CREDIT FOR SURPLUS SOLAR GENERATION BY PUBLIC SCHOOLS. (a) An electric utility or retail electric provider shall provide for net metering and contract with an independent school district so that:

(1) surplus electricity produced by a school building's solar electric generation panels is made available for sale to the electric transmission grid and distribution system; and

(2) the net value of that surplus electricity is credited to the district.

(b) For areas of this state in which customer choice has not been introduced, the commission by rule shall require that credits for electricity produced by a school building's solar electric generation panels reflect the value of the electricity that is made available for sale to the electric utility in accordance with federal regulations.

(c) For independent school districts in areas in which customer choice has been introduced, the district must sell the school buildings' surplus electricity produced to the retail electric provider that serves the school district's load at a value agreed to between the district and the provider that serves the district's load. The agreed value may be based on the clearing price of energy at the time of day that the electricity is made available to the grid. The independent organization identified in Section 39.151 shall develop procedures so that the amount of electricity purchased from a district under this section is accounted for in settling the total load served by the provider that serves the district's load. A district requesting net metering services for purposes of this section must have metering devices capable of providing measurements consistent with the independent organization's settlement requirements.

(d) A transmission and distribution utility shall make available to an independent school district for purposes of this section metering required for services provided under this section, including separate meters that measure the load and generator output or a single meter capable of measuring separately in-flow and out-flow at the point of common coupling meter point. The district must pay the differential cost of the metering unless the meters are provided at no additional cost. Except as provided by this section, Section 39.107 applies to metering under this section.

(e) A municipally owned utility or electric cooperative shall consider and complete the determinations regarding net metering service as provided by the federal Public Utility Regulatory Policies Act of 1978 (16 U.S.C. Section 2601 et seq., as amended by the federal Energy Policy Act of 2005 (Pub. L. No. 109-58)) after proceedings conducted in accordance with that law. A municipally owned utility or electric cooperative shall report the determinations made under this subsection to the State Energy Conservation Office and include in that report information regarding metering electricity generated by solar panels on public school building rooftops.

Added by Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 24, eff. September 1, 2007.

Sec. 39.915. CONSIDERATION AND APPROVAL OF CERTAIN TRANSACTIONS. (a) To protect retail customers in this state, and to ensure the continuation of cost-effective energy efficiency measures and delivery systems, notwithstanding any other provision of this title, an electric utility or transmission and distribution utility must report to and obtain approval of the commission before closing any transaction in which:

(1) the electric utility or transmission and distribution utility will be merged or consolidated with another electric utility or transmission and distribution utility;

(2) at least 50 percent of the stock of the electric utility or transmission and distribution utility will be

transferred or sold; or

(3) a controlling interest or operational control of the electric utility or transmission and distribution utility will be transferred.

(b) The commission shall approve a transaction under Subsection (a) if the commission finds that the transaction is in the public interest. In making its determination, the commission shall consider whether the transaction will adversely affect the reliability of service, availability of service, or cost of service of the electric utility or transmission and distribution utility. The commission shall make the determination concerning a transaction under this subsection not later than the 180th day after the date the commission receives the relevant report. The commission may extend the deadline provided by this subsection for not more than 60 days if the commission determines the extension is needed to evaluate additional information, to consider actions taken by other jurisdictions concerning the transaction, to provide for administrative efficiency, or for other good cause. If the commission has not made a determination before the expiration of the deadline provided by or extended under this subsection, the transaction is considered approved.

(c) Subsections (a) and (b) do not apply to a transaction described by Subsection (a) for which a definitive agreement was executed before April 1, 2007, if an electric utility or transmission and distribution utility or a person seeking to acquire or merge with an electric utility or transmission and distribution utility made a filing for review of the transaction under Section 14.101 before May 1, 2007, and the resulting proceeding was not withdrawn.

(d) If an electric utility or transmission and distribution utility or a person seeking to acquire or merge with an electric utility or transmission and distribution utility files with the commission a stipulation, representation, or commitment in advance of or as part of a filing under this section or under Section 14.101, the commission may enforce the stipulation, representation, or commitment to the extent that the stipulation, representation, or commitment is consistent with the standards provided by this section and Section 14.101. The commission may reasonably interpret and enforce conditions adopted under this section.

Added by Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 25, eff. September 1, 2007.

Amended by:

Acts 2017, 85th Leg., R.S., Ch. 200 (S.B. 735), Sec. 4, eff. May 27, 2017.

Sec. 39.916. INTERCONNECTION OF DISTRIBUTED RENEWABLE GENERATION. (a) In this section:

(1) "Distributed renewable generation" means electric generation with a capacity of not more than 2,000 kilowatts provided by a renewable energy technology that is installed on a retail electric customer's side of the meter.

(2) "Distributed renewable generation owner" means:

(A) an owner of distributed renewable generation;

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

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

(3) "Interconnection" means the right of a distributed renewable generation owner to physically connect distributed renewable generation to an electricity distribution system, and the technical requirements, rules, or processes for the connection.

(4) "Renewable energy technology" means any technology that relies exclusively on an energy source that is naturally regenerated over a short time and is derived from the sun directly or indirectly or from moving water or other natural movements or mechanisms of the environment. The term includes a technology that relies on energy derived from the sun directly, on wind, geothermal, hydroelectric, wave, or tidal energy, or on

biomass or biomass-based waste products, including landfill gas. The term does not include a technology that relies on an energy resource derived from a fossil fuel, a waste product from a fossil fuel, or a waste product from an inorganic source.

(b) A transmission and distribution utility or electric utility shall allow interconnection if:

(1) the distributed renewable generation to be interconnected has a five-year warranty against breakdown or undue degradation; and

(2) the rated capacity of the distributed renewable generation does not exceed the transmission and distribution utility or electric utility service capacity.

(c) A customer may request interconnection by filing an application for interconnection with the transmission and distribution utility or electric utility. Procedures of a transmission and distribution utility or electric utility for the submission and processing of a customer's application for interconnection shall be consistent with rules adopted by the commission regarding interconnection.

(d) The commission by rule shall establish safety, technical, and performance standards for distributed renewable generation that may be interconnected. In adopting the rules, the commission shall consider standards published by the Underwriters Laboratories, the National Electric Code, the National Electric Safety Code, and the Institute of Electrical and Electronics Engineers.

(e) A transmission and distribution utility, electric utility, or retail electric provider may not require a distributed renewable generation owner whose distributed renewable generation meets the standards established by rule under Subsection (d) to purchase an amount, type, or classification of liability insurance the distributed renewable generation owner would not have in the absence of the distributed renewable generation.

(f) A transmission and distribution utility or electric utility shall make available to a distributed renewable generation owner for purposes of this section metering required for services provided under this section, including separate meters that measure the load and generator output or a single meter capable of measuring in-flow and out-flow at the point of common coupling meter point. The distributed renewable generation owner must pay the differential cost of the metering unless the meters are provided at no additional cost. Except as provided by this section, Section 39.107 applies to metering under this section.

(g) Repealed by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 46(a)(5), eff. September 1, 2023.

(h) An electric utility or retail electric provider may contract with a distributed renewable generation owner so that:

(1) surplus electricity produced by distributed renewable generation is made available for sale to the transmission grid and distribution system; and

(2) the net value of that surplus electricity is credited to the distributed renewable generation owner.

[(i) reserved]

(j) For distributed renewable generation owners in areas in which customer choice has been introduced, the distributed renewable generation owner must sell the owner's surplus electricity produced to the retail electric provider that serves the distributed renewable generation owner's load at a value agreed to between the distributed renewable generation owner and the provider that serves the owner's load which may include, but is not limited to, an agreed value based on the clearing price of energy at the time of day that the electricity is made available to the grid or it may be a credit applied to an account during a billing period that may be carried over to subsequent billing periods until the credit has been redeemed. The independent organization identified in Section 39.151 shall develop procedures so that the amount of electricity purchased from a distributed renewable generation owner under this section is accounted for in settling the total load served by the provider that serves that owner's load by January 1, 2009. A distributed renewable generation owner requesting net metering services for purposes of this section must have metering devices capable of providing measurements consistent with the independent organization's settlement requirements.

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

Added by Acts 2007, 80th Leg., R.S., Ch. 939 (H.B. 3693), Sec. 26, eff. September 1, 2007.

Amended by:

Acts 2011, 82nd Leg., R.S., Ch. 1070 (S.B. 981), Sec. 1, eff. September 1, 2011.

Acts 2011, 82nd Leg., R.S., Ch. 1070 (S.B. 981), Sec. 2, eff. September 1, 2011.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 38, eff. September 1, 2023.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 46(a)(5), eff. September 1, 2023.

Sec. 39.9165. DISTRIBUTED GENERATION FACILITY REPORTING. (a) In this section:

(1) "Distributed generation facility" is an electrical generating facility, including an energy storage facility, that:

(A) is connected at a voltage less than 60 kilovolts; and

(B) is capable of being connected in parallel operation to the utility system.

(2) "Transmission service provider" means a transmission and distribution utility, municipally owned utility, or electric cooperative that owns or operates facilities used for the transmission of electricity.

(b) An independent organization certified under Section 39.151 may establish protocols to require a person who owns or operates a distributed generation facility interconnected to a utility system operating in the power region served by the independent organization, or who seeks to interconnect such a facility, to provide to the interconnecting transmission and distribution utility, municipally owned utility, or electric cooperative information about the distributed generation facility that the independent organization determines is necessary for maintaining system reliability.

(b-1) Protocols adopted under Subsection (b) may require that the information be provided as a condition to interconnecting the distributed generation facility.

(c) An independent organization certified under Section 39.151 may establish protocols to require a transmission service provider operating in the power region served by the independent organization to report to the independent organization, in aggregate by delivery point, information the independent organization determines is necessary for maintaining system reliability regarding distributed generation facilities and distribution-connected loads that:

(1) are not registered with the independent organization; and

(2) are connected to the utility systems served by the transmission service provider.

(d) An independent organization certified under Section 39.151 may establish protocols to require a transmission and distribution utility, municipally owned utility, or electric cooperative that is not required to report load information directly to the independent organization regarding the delivery points interconnected with its facilities to provide information to the utility's or cooperative's transmission service provider for purposes of the report described by Subsection (c).

(e) For a distributed generation facility interconnected before September 1, 2023, any protocols the independent organization certified under Section 39.151 establishes under Subsections (c) and (d) may require a transmission and distribution utility, municipally owned utility, or electric cooperative to:

(1) request information about the distributed generation facility from the owner or operator of the facility; and

(2) in the absence of any timely response to the request for information under Subdivision (1) or if the information reasonably appears to be incorrect, provide to its transmission service provider a good-faith estimate of the information based on field observation or other data using reasonable engineering judgment.

(f) Notwithstanding Subsection (e), the transmission and distribution utility, municipally owned utility, or electric cooperative, in fulfilling any reporting obligation, may rely on any existing record regarding the information required for a distributed generation facility, if the transmission and distribution utility, municipally owned utility, or electric cooperative reasonably believes the information is accurate.

Added by Acts 2021, 87th Leg., R.S., Ch. 426 (S.B. 3), Sec. 19, eff. June 8, 2021.

Amended by:

Acts 2023, 88th Leg., R.S., Ch. 331 (H.B. 3390), Sec. 1, eff. June 2, 2023.

Sec. 39.917. TEXAS ELECTRIC GRID SECURITY COUNCIL. (a) The legislature finds that there is a public interest in mitigating the risk of cyber and physical attacks that may affect the reliability of electric systems operating in Texas. The Texas Electric Grid Security Council is established as an advisory body to facilitate the creation, aggregation, coordination, and dissemination of best security practices for the electric industry, including the generation, transmission, and delivery of electricity.

(b) The Texas Electric Grid Security Council is composed of:

(1) the commissioner designated as presiding officer of the commission under Section 12.052 or a representative designated by the commissioner;

(2) the chief executive officer of the independent organization certified under Section 39.151 for the ERCOT power region or a representative designated by the chief executive officer; and

(3) the governor or a representative designated by the

governor.

(c) The member of the council designated by Subsection (b)(1) shall serve as presiding officer.

(d) The council shall convene at the call of the presiding officer.

(e) A member of the council is not entitled to compensation. Members are entitled to reimbursement for travel and other necessary expenses related to the activities of the council as provided by the General Appropriations Act.

(f) A member of the council may apply for a secret security clearance or an interim security clearance granted by the United States government. A member of the council may not access classified information or participate in a briefing or meeting involving classified information unless the member has a secret security clearance.

(g) The independent organization certified under Section 39.151 shall:

(1) provide information and resources requested by the council; and

(2) maintain nonclassified information obtained or created by the council, provide members of the council with access to the information, and retain the information for five years after the date that the council obtains or creates the information.

(h) In carrying out its functions, the council may consult and coordinate with:

(1) the Texas Division of Emergency Management;

(2) the United States Department of Energy;

(3) the United States Department of Homeland Security;

(4) the North American Electric Reliability Corporation;

(5) the Texas Reliability Entity;

(6) federal and state agencies;

(7) members of the electric industry; and

(8) grid security experts.

(i) On a request by the governor, the lieutenant governor, the chair of the house of representatives committee having jurisdiction over energy utility regulation, or the chair of the senate committee having jurisdiction over energy utility regulation, the council shall issue to the requestor recommendations regarding:

(1) the development of educational programs or marketing materials to promote the development of a grid security workforce;

(2) the development of grid security best practices;

(3) preparation for events that threaten grid security; and

(4) amendments to the state emergency management plan to ensure coordinated and adaptable response and recovery efforts after events that threaten grid security.

(j) The council may prepare a report outlining grid security response efforts that do not involve classified or highly sensitive, company-specific information. If the council prepares the report, the council shall deliver the report to the governor, lieutenant governor, and legislature on or before the December 1 immediately preceding a regular session of the legislature.

(k) The meetings of the council and information obtained or created by the council are not subject to the requirements of Chapter 551 or 552, Government Code.

Added by Acts 2019, 86th Leg., R.S., Ch. 516 (S.B. 475), Sec. 1, eff. June 7, 2019.

Sec. 39.918. UTILITY FACILITIES FOR POWER RESTORATION AFTER SIGNIFICANT POWER OUTAGE. (a) In this section, "significant power outage" means an event that:

(1) results in a loss of electric power that:

(A) affects a significant number of distribution customers of a transmission and distribution utility and has lasted or is expected to last for at least six hours;

(B) affects distribution customers of a transmission and distribution utility in an area for which the governor has issued a disaster or emergency declaration;

(C) affects distribution customers served by a radial transmission or distribution facility, creates a risk to public health or safety, and has lasted or is expected to last for at least 12 hours; or

(D) creates a risk to public health or safety because it affects a critical infrastructure facility that serves the public such as a hospital, health care facility, law enforcement facility, fire station, or water or wastewater facility; or

(2) causes the independent system operator to order a transmission and distribution utility to shed load.

(a-1) The Texas Division of Emergency Management, the independent organization certified under Section 39.151 for the ERCOT power region, or the executive director of the commission may determine that a power outage other than an outage described by Subsection (a) is a significant power outage for the purposes of this section.

(b) Notwithstanding any other provision of this subtitle, a transmission and distribution utility may:

(1) lease and operate facilities that provide temporary emergency electric energy to aid in restoring power to the utility's distribution customers during a significant power outage in which:

(A) the independent system operator has ordered the utility to shed load; or

(B) the utility's distribution facilities are not being fully served by the bulk power system under normal operations; and

(2) procure, own, and operate, or enter into a cooperative agreement with other transmission and distribution utilities to procure, own, and operate jointly, transmission and distribution facilities that have a lead time of at least six months and would aid in restoring power to the utility's distribution customers following a significant power outage. In this section, long lead time facilities may not be electric energy storage equipment or facilities under Chapter 35.

(c) A transmission and distribution utility that leases and operates facilities under Subsection (b)(1) may not sell electric energy or ancillary services from those facilities.

(d) Facilities described by Subsection (b)(1):

(1) must be operated in isolation from the bulk power system; and

(2) may not be included in independent system operator:

(A) locational marginal pricing calculations;

(B) pricing; or

(C) reliability models.

(e) A transmission and distribution utility that leases and operates facilities under Subsection (b)(1) shall ensure, to the extent reasonably practicable, that retail customer usage during operation of those facilities is adjusted out of the usage reported for billing purposes by the retail customer's retail electric provider.

(f) A transmission and distribution utility shall, when reasonably practicable, use a competitive bidding process to lease facilities under Subsection (b)(1).

(g) A transmission and distribution utility that leases and operates facilities under Subsection (b)(1) or that procures, owns, and operates facilities under Subsection (b)(2) shall include in the utility's emergency operations plan filed with the commission, as described by Section 186.007, a detailed plan on the utility's use of those facilities.

(h) The commission shall permit:

(1) a transmission and distribution utility that leases and operates facilities under Subsection (b)(1) to recover the reasonable and necessary costs of leasing and operating the facilities, including the present value of future payments required under the lease, using the rate of return on investment established in the commission's final order in the utility's most recent base rate proceeding; and

(2) a transmission and distribution utility that procures, owns, and operates facilities under Subsection (b)(2) to recover the reasonable and necessary costs of procuring, owning, and operating the facilities, using the rate of return on investment established in the commission's final order in the utility's most recent base rate proceeding.

(i) The commission shall authorize a transmission and distribution utility to defer for recovery in a future ratemaking proceeding the incremental operations and maintenance expenses and the return, not otherwise recovered in a rate proceeding, associated with the leasing or procurement, ownership, and operation of the facilities.

(j) A transmission and distribution utility may request recovery of the reasonable and necessary costs of leasing or procuring, owning, and operating facilities under this section, including any deferred expenses, through a proceeding under Section 36.210 or in another ratemaking proceeding. A lease under Subsection (b)(1) must be treated as a capital lease or finance lease for ratemaking purposes.

(k) Repealed by Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 46(a)(6), eff. September 1, 2023.

Added by Acts 2021, 87th Leg., R.S., Ch. 698 (H.B. 2483), Sec. 1, eff. September 1, 2021.

Amended by:

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 39, eff. September 1, 2023.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 40, eff. September 1, 2023.

Acts 2023, 88th Leg., R.S., Ch. 410 (H.B. 1500), Sec. 46(a)(6), eff. September 1, 2023.

Acts 2023, 88th Leg., R.S., Ch. 768 (H.B. 4595), Sec. 22.004, eff. September 1, 2023.

Sec. 39.919. AVERAGE TOTAL RESIDENTIAL LOAD REDUCTION GOALS. (a) The commission by rule shall establish goals in the ERCOT power region to reduce the average total residential load.

(b) The rules adopted under Subsection (a) must provide for the adoption of a program that:

(1) provides demand response participation to residential customers where reasonably available;

(2) promotes the use of smart metering technology;

(3) is capable of responding to an emergency energy alert about low operating reserves issued by the independent organization certified under Section 39.151 for the ERCOT power

region;

(4) provides opportunities for demand response providers to contract with retail electric providers to provide demand response services;

(5) ensures the program does not impact the critical needs of vulnerable populations;

(6) facilitates the widespread deployment of smart responsive appliances and devices in a manner that enables the customer's appliance or device to be enrolled as part of a demand response product or plan offered by a retail electric provider;

(7) establishes the method by which the components of the ratio described by Subsection (c) are calculated for purposes of determining whether the goals described by Subsection (a) have been achieved;

(8) provides for achievement of demand reductions within both summer and winter seasons; and

(9) allows a retail electric provider that offers a demand response program under this section to obtain funding for the demand response program through an energy efficiency incentive program established under Section 39.905 if the program complies with commission requirements related to the evaluation, measurement, and verification of demand response programs adopted under Section 39.905.

(c) The goals described by Subsection (a) must be calculated as a ratio by dividing the amount of load reduced at peak demand by the total amount of demand, at the same time, of all residential customers who have responsive appliances or devices at their premises that reduce the electric consumption of the customers.

(d) A transmission and distribution utility required to provide an energy efficiency incentive program under Section 39.905 may use up to 10 percent of the budgeted spending for demand response programs on the programs described by Subsection (b)(9).

Added by Acts 2023, 88th Leg., R.S., Ch. 945 (S.B. 1699), Sec. 5, eff. September 1, 2023.