PROJECT NO. 48525

RULEMAKING RELATING TO ADVANCED METERING	§ § §	**PUBLIC UTILITY COMMISSION** **OF TEXAS**

PROPOSAL FOR PUBLICATION OF AMENDMENTS TO §§25.5, 25.130, AND 25.133 AS APPROVED AT THE NOVEMBER 14, 2019 OPEN MEETING

The Public Utility Commission of Texas (commission) proposes amendments to §25.5, relating to definitions; §25.130, relating to advanced metering; and §25.133, relating to non-standard metering service. The amendments to §§25.130 and 25.133 conform the rules to Senate Bill 1145, 85th Legislature, Regular Session, which amended Public Utility Regulatory Act (PURA) §39.452, and to the following bills from the 86th Legislature, Regular Session: House Bill 853, which amended PURA §39.5521, House Bill 986, which amended PURA §39.402, and House Bill 1595, which amended PURA §39.5021. These bills encourage deployment of advanced metering and meter information networks by extending the applicability of PURA §39.107(h) and (k) to electric utilities providing service in areas outside the Electric Reliability Council of Texas (ERCOT).

The amendments also remove the requirement for an electric utility to offer the home area network (HAN) feature due to limited customer interest and set minimum capabilities for on-demand reads of a customer's advanced meter. In addition, the amendments clarify and define rule language; remove rule language relating to an electric utility's limitation of liability because these provisions are addressed in the electric utility's tariff; and remove obsolete and other unnecessary rule language.

Growth Impact Statement

The agency provides the following governmental growth impact statement for the proposed rule, as required by Texas Government Code §2001.0221. The agency has determined that for each year of the first five years that the proposed amendments are in effect, the following statements will apply:

(1) the proposed amendments will not create a government program and will not eliminate a government program;

(2) implementation of the proposed amendments will not require the creation of new employee positions and will not require the elimination of existing employee positions;

(3) implementation of the proposed amendments will not require an increase and will not require a decrease in future legislative appropriations to the agency;

(4) the proposed amendments will not require an increase and will not require a decrease in fees paid to the agency;

(5) the proposed amendments will not create a new regulation;

(6) the proposed amendments will expand §25.130 by setting a requirement for the minimum provision of on-demand reads an electric utility must be capable of providing;

(7) the proposed amendments will conform §25.130 and §25.133 to the legislation described in the first paragraph by expressly applying §25.130 and §25.133 to electric utilities outside the ERCOT power region; and

(8) the proposed rules will not affect this state's economy.

Fiscal Impact on Small and Micro-Businesses and Rural Communities

There is no adverse economic effect anticipated for small businesses, micro-businesses, or rural communities as a result of implementing the proposed amendments. Accordingly, no economic impact statement or regulatory flexibility analysis is required under Texas Government Code §2006.002(c).

Takings Impact Analysis

The commission has determined that the proposed amendments will not be a taking of private property as defined in chapter 2007 of the Texas Government Code.

Fiscal Impact on State and Local Government

Therese Harris, Director of Infrastructure Analysis and Mapping, has determined that for the first five-year period the proposed amendments are in effect, there will be no fiscal implications for the state or for units of local government under Texas Government Code §2001.024(a)(4) as a result of enforcing or administering the amendments.

Public Benefits

Therese Harris has also determined that for each year of the first five years the proposed amendments are in effect, the anticipated public benefits expected as a result of the adoption of the proposed amendments will be conforming §25.130 and §25.133 to the legislation described in the first paragraph, setting minimum capabilities for on-demand reads of a customer's advanced meter an electric utility must provide, and removing unnecessary language from the rules.

There will be no probable economic cost to persons required to comply with the proposed amendments.

Local Employment Impact Statement

For each year of the first five years the proposed amendments are in effect there should be no effect on a local economy; therefore, no local employment impact statement is required under Texas Government Code §2001.022.

Costs to Regulated Persons

Texas Government Code §2001.0045(b) does not apply to this rulemaking because the Public Utility Commission is expressly excluded under subsection §2001.0045(c)(7).

Public Hearing

The commission staff will conduct a public hearing on this rulemaking, if requested in accordance with Texas Government Code §2001.029, at the commission's offices located in the William B. Travis Building, 1701 North Congress Avenue, Austin, Texas 78701 on January 17, 2020 at 9:00 AM. The request for a public hearing must be received by January 13, 2019. If no request for a public hearing is received and the commission staff cancels the hearing, it will make a filing in this project prior to the scheduled date for the hearing.

Public Comments

Initial comments on the proposed amendments may be submitted to the commission's filing clerk at 1701 North Congress Avenue, P.O. Box 13326, Austin, TX 78711-3326 by January 13, 2019. Reply comments may be submitted by January 23, 2020. Comments should be organized in a manner consistent with the organization of the proposed rule. The commission invites specific comments regarding the costs associated with, and benefits that will be gained by, implementation of the proposed rule. The commission will consider the costs and benefits in deciding whether to modify the proposed rule on adoption. All comments should refer to project number 48525. Sixteen copies of comments are required to be filed under §22.71(c) of 16 Texas Administrative Code.

Statutory Authority

These amendments are proposed under §14.001 of the Public Utility Regulatory Act, Tex. Util. Code Ann. (West 2016 and Supp. 2017) (PURA), which provides the commission with the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by PURA that is necessary and convenient to the exercise of that power and jurisdiction; PURA §14.002, which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; PURA §36.003, which grants the commission the authority to ensure that each rate be just and reasonable and not unreasonably preferential, prejudicial, or discriminatory; PURA §39.107, which grants the commission the authority to approve electric utility surcharges for the deployment of advanced meters, adopt rules relating to the transfer of customer data, and approve non-discriminatory rates for metering service; and PURA §§39.402, 39.452, 39.5021 and 39.5521, which permit the electric utilities outside of the ERCOT region that elect to deploy advanced meters and meter information networks to recover reasonable and necessary deployment costs and subjects the deployment to commission rules adopted under PURA §39.107(h) and (k).

Cross reference to statutes: Public Utility Regulatory Act §§ 14.001, 14.002, 36.003, 39.107, 39.402, 39.452, 39.5021 and 39.5521.

§25.130. Advanced Metering.

(a) **Purpose.** This section addresses the deployment, operation, and cost recovery for advanced metering systems~~The purposes of this section are to authorize electric utilities to assess a nonbypassable surcharge to use to recover costs incurred for deploying advanced metering systems that are consistent with this section; increase the reliability of the regional electrical network; encourage dynamic pricing and demand response; improve the deployment and operation of generation, transmission and distribution assets, and provide more choices for electric customers~~.

(b) **Applicability**. This section is applicable to all electric utilities, including transmission and distribution utilities.~~, other than an electric utility that, pursuant to Public Utility Regulatory Act (PURA) §39.452(d)(1), is not subject to PURA §39.107; and to the Electric Reliability Council of Texas (ERCOT).~~ Any requirement applicable to an electric utility in this section that relates to retail electric providers (REPs) or REPs of record is applicable only to electric utilities operating in areas open to customer choice.

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

(1) Advanced meter -- Any new or appropriately retrofitted meter that functions as part of an advanced metering system and that has the minimum system features specified in this section, except to the extent the electric utility has obtained a waiver of a minimum feature from the commission.

(2) – (3) (No change.)

~~(4) Dynamic Pricing -- Retail pricing for electricity consumed that varies during different times of the day.~~

(4)~~(5)~~ Enhanced ~~Non-standard~~ advanced meter -- A meter that contains features and functions in addition to the AMS features in the deployment plan approved by the commission.

(5) Web portal --The website made available on the internet in compliance with this section by an electric utility or a group of electric utilities through which read-only access to AMS usage data is made available to the customer, the customer's REP of record, and entities authorized by the customer.

(d) **Deployment and use of advanced meters.**

(1) Deployment and use of an AMS by an electric utility is voluntary unless otherwise ordered by the commission. However, deployment and use of an AMS for which an electric utility seeks a surcharge for cost recovery must ~~shall~~ be consistent with this section, except to the extent that the electric utility has obtained a waiver from the commission.

(2) Six months prior to initiating deployment of an AMS or as soon as practicable after the effective date of this section, whichever is later, an electric utility that intends to deploy an AMS must ~~shall~~ file a statement ~~Statement~~ of AMS functionality~~Functionality~~, and either a notice ~~Notice~~ of deployment ~~Deployment~~ or a request ~~Request~~ for approval ~~Approval~~ of deployment~~Deployment~~. An electric utility may request a surcharge under ~~pursuant to~~ subsection (k) of this

section in combination with a notice ~~Notice~~ of deployment ~~Deployment~~ or a request ~~Request~~ for approval ~~Approval~~ of deployment~~Deployment~~, or separately. A proceeding that includes a request to establish or amend a surcharge will ~~shall~~ be a ratemaking proceeding and a proceeding involving only a request ~~Request~~ for approval ~~Approval~~ of deployment ~~Deployment~~ will ~~shall~~ not be a ratemaking proceeding.

(3) The statement ~~Statement~~ of AMS functionality ~~Functionality~~ must~~shall~~:

(A) state whether the AMS meets the requirements specified in subsection (g) of this section and what additional features, if any, it will have~~perform~~;

(B) describe any variances between technologies and meter functions within the electric utility's ~~its~~ service territory; and

(C) state whether the electric utility intends to seek a waiver of any provision of this section in its request for surcharge.

(4) A deployment plan ~~Deployment Plan~~ must ~~shall~~ contain the following information:

(A) Type of meter technology;

(B) Type and description of communications equipment in the AMS;

(C) Systems that will be developed during the deployment period;

(D) A timeline for the web portal development or integration into an existing web portal;

(E) A deployment schedule by specific area (geographic information); and

~~When postings of monthly status reports on the electric utility's website will commence; and~~

(F) A schedule for deployment of web portal functionalities.

(5) An electric utility must ~~shall~~ file with the deployment plan~~Deployment Plan~~, testimony and other supporting information, including estimated costs for all AMS components, estimated net operating cost savings expected in connection with implementing the deployment plan~~Deployment Plan~~, and the contracts for equipment and services associated with the deployment plan~~Deployment Plan~~, that prove the reasonableness of the plan.

(6) Competitively sensitive information contained in the deployment plan~~Deployment Plan,~~ and the monthly progress reports required under paragraph (9) of this subsection~~,~~ may be filed confidentially. An electric utility's deployment plan~~Deployment Plan~~ must ~~shall~~ be maintained and made available for review on the electric utility's website~~ for REP access~~. Competitively sensitive information contained in the deployment plan ~~Deployment Plan~~ must ~~shall~~ be maintained and made available at the electric utility's offices in Austin. Any REP that wishes to review competitively sensitive information contained in the electric utility's deployment plan available at its Austin office~~,~~ may do so during normal business hours upon reasonable advanced notice to the electric utility and after executing a non-disclosure agreement with the electric utility.

(7) If the request for approval of a deployment plan ~~Deployment Plan~~ contains the information described in paragraph (4) of this subsection and the AMS features described in subsection (g)(1) of this section, then the commission will ~~shall~~ approve or disapprove the deployment plan ~~Deployment Plan~~ within 150 days, but this deadline may be extended by the commission for good cause.

(8) An electric utility's treatment of AMS, including technology, functionalities, services, deployment, operations, maintenance, and cost recovery must ~~shall~~ not be unreasonably discriminatory, prejudicial, preferential, or anticompetitive.

(9) Each electric utility must ~~shall~~ provide progress reports on a monthly basis ~~and status reports every six months~~ following the filing of its deployment plan ~~Deployment Plan~~ with the commission until deployment is complete. Upon filing of such reports, an ~~the~~ electric utility operating in an area open to customer choice must~~shall~~ notify all ~~certified~~ REPs of the filing through standard market notice procedures. A monthly progress report must ~~shall~~ be filed within 15 days of the end of the month to which it applies, and must ~~shall~~ include the following information:

(A) the number of advanced meters installed, listed by electric service identifier ~~ESI IDs~~ for meters in the Electric Reliability Council of Texas (ERCOT) region. Additional deployment information if available must ~~may~~ also be provided~~listed~~, such as county, city, zip code, feeder numbers, and any other easily discernable geographic identification available to the electric utility about the meters that have been deployed;

(B) significant delays or deviation from the deployment plan ~~Deployment Plan~~ and the reasons for the delay or deviation;

(C) a description of significant problems the electric utility has experienced with an AMS, with an explanation of how the problems are being addressed;

(D) the number of advanced meters that have been replaced as a result of problems with the AMS; and

(E) the status of deployment of features identified in the deployment plan ~~Deployment Plan~~ and any changes in deployment of these features.

(10) If an electric utility has received approval of its deployment plan ~~Deployment Plan~~ from the commission, the electric utility must ~~shall~~ obtain commission approval before making any changes to its AMS that would affect the ~~a REP's~~ ability of a customer, the customer's REP of record, or entities authorized by the customer to utilize any of the AMS features identified in the electric utility's deployment plan ~~Deployment Plan~~ by filing a request for amendment to its deployment plan~~Deployment Plan~~. In addition, an electric utility may request commission approval for other changes in its approved deployment plan~~Deployment Plan~~. The commission will ~~shall~~ act upon the request for an amendment to the deployment plan ~~Deployment Plan~~ within 45 days of submission of the request, unless good cause exists for additional time. If an electric utility filed a notice ~~Notice~~ of deployment~~Deployment~~, the electric utility must ~~shall~~ file an amendment to its notice ~~Notice~~ of deployment ~~Deployment~~ at least 45 days before making any changes to its AMS that would affect the ~~a REP's~~ ability of a customer, the customer's REP of record, or entities authorized by the customer to utilize any of the AMS features identified in the electric utility's notice ~~Notice~~ of deployment~~Deployment~~. This paragraph does not in any way preclude the electric utility from conducting its normal operations and

maintenance with respect to the electric utility's transmission and distribution system and metering systems.

(11) During and following deployment, any outage related to normal operations and maintenance that affects a REP's ability to obtain information from ~~with~~ the system must ~~shall~~ be communicated to the REP through the outage and~~/~~ restoration notice process according to Applicable Legal Authorities, as defined in §25.214(d)(1) of this title (relating to Tariff for Retail Delivery Service). Notification of any planned or unplanned outage that affects access to customer usage data must be posted on the electric utility's web portal home page.

(12) An ~~The~~ electric utility subject to §25.343 of this title (relating to Competitive Energy Services) must ~~shall~~ not provide any advanced metering equipment or service that is deemed a competitive energy service under that section. ~~§25.343 of this title (relating to Competitive Energy Services).~~ Any functionality of the AMS that is a required feature ~~function~~ under this section or that is included in an approved deployment plan ~~Deployment Plan~~ or otherwise approved by the commission does not constitute a competitive energy service under §25.343 of this title.

~~(13) An electric utility's deployment and provision of AMS services and features, including but not limited to the features required in subsection (g) of this section, are subject to the limitation of liability provisions found in the electric utility's tariff.~~

(e) **Technology requirements.** Except for pilot programs, an electric utility must ~~shall~~ not deploy AMS technology that has not been successfully installed previously with at least 500 advanced meters in North America, Australia, Japan, or Western Europe.

(f) **Pilot programs.** An electric utility may deploy AMS with up to 10,000 meters that do not meet the requirements of subsection (g) of this section in a pilot program, to gather additional information on metering technologies, pricing, and management techniques, for studies, evaluations, and other reasons. A pilot program may be used to satisfy the requirement in subsection (e) of this section. An electric utility is not required to obtain commission approval for a pilot program. Notice of the pilot program and opportunity to participate must ~~shall~~ be sent by the electric utility to all REPs.

(g) **AMS features.**

(1) An AMS must ~~shall~~ provide or support the following minimum system features~~ in order to obtain cost recovery through a surcharge underpursuant to subsection (k) of this section~~:

(A) automated or remote meter reading;

(B) two-way communications between the meter and the electric utility;

(C) remote disconnection and reconnection capability for meters rated at or below 200 amps~~, provided that an electric utility shall be considered in compliance with this provision if it makes this function available in all advanced meters installed after the effective date of this rule, and the following meters shall also be considered in compliance with this~~

~~provision: those advanced meters that were ordered prior to the effective date of this rule, not to exceed 65,000 meters over the number of meters received or ordered as of May 10, 2007, and are provisioned with all the features enumerated in this paragraph except remote disconnect and reconnect capability, if those advanced meters are installed by December 31, 2007, and the number of advanced meters installed with all the features enumerated in this paragraph except remote disconnect and reconnect capability does not exceed 18% of the total number of advanced meters installed by the electric utility pursuant to a Deployment Plan~~.

(D) ~~the capability to~~ time-stamped meter data sent to the independent organization or regional transmission organization for purposes of wholesale settlement, consistent with time tolerance and other standards adopted by the independent organization or regional transmission organization;

(E) ~~the capability to provide direct, real-time~~ access to customer usage data by ~~to~~ the customer, ~~and~~ the customer's REP of record, and entities authorized by the customer provided that~~:~~

~~(i)~~ 15-minute interval or shorter~~hourly~~ data from the electric utility's AMS must ~~shall~~ be transmitted to the electric utility's or a group of electric utilities' web portal on a day-after basis~~.~~;

~~(ii) the commission staff using a stakeholder process, as soon as practicable shall determine, subject to commission approval, when~~

~~and how 15-minute IDR data shall be made available on the electric utility's web portal.~~

(F) capability to provide on-demand reads of a customer's advanced meter through the graphical user interface of an electric utility's or a group of electric utilities' web portal when requested by a customer, the customer's REP of record, or entities authorized by the customer subject to network traffic such as interval data collection, market orders if applicable, and planned and unplanned outages~~means by which the REP can provide price signals to the customer~~;

(G) for an electric utility that provides access through an application programming interface, the capability to provide at least two on-demand reads per hour per meter of a customer's advanced meter, subject to network traffic such as interval data collection, market orders if applicable, and planned and unplanned outages. An electric utility in the ERCOT region must be able to accommodate at least 6,000 on-demand read requests per day through this method, subject to network traffic~~the capability to provide 15-minute or shorter interval data to REPs, customers, and the independent organization or regional transmission organization, on a daily basis, consistent with data availability, transfer and security standards adopted by the independent organization or regional transmission organization~~;

(H) on-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as in American National Standards Institute (ANSI) C12.19 tables;

(I) open standards and protocols that comply with nationally recognized non-proprietary standards such as ANSI C12.22, including future revisions ~~thereto~~;

(J) for an electric utility in the ERCOT region, the capability to communicate with devices inside the premises, including, but not limited to, usage monitoring devices, load control devices, and prepayment systems through a home area network (HAN), based on open standards and protocols that comply with nationally recognized non-proprietary standards such as ZigBee, Home-Plug, or the equivalent through the electric utility's AMS. This requirement applies only to a HAN device paired to a meter and in use at the time that the version of the web portal approved in Docket Number 47472 was implemented and terminates when the HAN device is disconnected at the request of the customer or a move-out transaction occurs for the customer's premises; and

(K) the ability to upgrade these features ~~minimum capabilities~~ as the need arises ~~technology advances and, in the electric utility's determination, become economically feasible~~.

~~(2) An electric utility shall offer, as discretionary services in its tariff, installation of non-standard meters and advanced meter features.~~

~~(A) A REP may require the electric utility to provide non-standard advanced meters, additional metering technology, or advanced meter features not specifically offered in the electric utility's tariff, that are technically feasible, generally available in the market, and compatible with the electric utility's AMS;~~

~~(B) The REP shall pay the reasonable differential cost for the non-standard advanced meters or features.~~

~~(C) Upon request by a REP, an electric utility shall expeditiously provide a report to the REP that includes an evaluation of the cost and a schedule for providing the nonstandard advanced meters or advanced meter features of interest to the REP. The REP shall pay a reasonable discretionary services fee for this report. This discretionary services fee shall be included in the electric utility's tariff.~~

~~(D) If an electric utility agrees to deploy non-standard advanced meters or advanced meter features not addressed in its tariff at the request of the REP, the electric utility shall expeditiously apply to amend its tariff to specifically include the non-standard advanced meters or meter features that it agreed to deploy.~~

(2)~~(3)~~ ~~An electric utility may petition the commission for~~ A ~~a~~ waiver from any of the requirements of paragraph (1) of this subsection ~~for portions of its service area where~~ may be granted by the commission if it would be uneconomic or technically infeasible to implement ~~particular system features. A waiver may also~~

~~be granted for an AMS that exceeds~~ or there is an adequate substitute for that ~~the~~ particular requirement ~~requirements in paragraph (1) of this subsection~~. The electric utility must ~~shall provide all relevant studies and cost-benefit analysis and other evidence supporting its waiver request and shall bear the~~ meet its burden of proof in its waiver request. ~~An electric utility that has received a waiver shall explain in the report required by subsection (d)(7) of this section, technology changes and changes in the cost of deployment or savings to the electric utility that would make it economic or technically feasible to offer the system features in the affected portions of its service area. Any waiver granted by the commission shall extend only to those costs and expenses for which the waiver is granted in any proceeding in which the electric utility seeks to recover its costs through the surcharge mechanism addressed in subsection (k) of this section.~~

(3)~~(4)~~ In areas where there is not a commission-approved independent regional transmission organization, standards referred to in this section for time tolerance and data transfer and security may be approved by a regional transmission organization approved by the Federal Energy Regulatory Commission or, if there is no approved regional transmission organization, by the commission.

(4)~~(5)~~ Once an electric utility has deployed its advanced meters, it may add or enhance features provided by AMS, as technology evolves ~~and in accordance with Applicable Legal Authorities~~. The electric utility must ~~shall~~ notify the commission and REPs of any such additions or enhancements at least three months in advance of deployment, with a description of the features, the deployment and notification plan, and the cost of such additions or enhancements, and must ~~shall~~ follow the monthly progress report process described in subsection (d)(9)~~(8)~~ of this section until the enhancement process is complete.

~~(6) Beginning January 1, 2008, or as soon as such meters are commercially available from the electric utility's current vendor, whichever is earlier, an electric utility shall replace, at no cost to the customer, an advanced meter with all the features enumerated in paragraph (1) of this subsection except remote disconnect and reconnect capability, if: the meter has reached the end of its useful life; the meter has been removed for repair; the premises at which the meter is located has experienced an unusually high number of disconnections and reconnections; or the REP has informed the electric utility that its customer has agreed to utilize a prepaid service and the REP has requested a meter with remote disconnection and reconnection capability. If by January 1, 2009, requests by REPs for replacement of advanced meters with all the features enumerated in paragraph (1) of this subsection except remote disconnect and reconnect capability exceed 20% of those meters, then the electric utility shall replace all of those meters as soon as possible with meters that meet the requirements of paragraph (1) of this subsection and have remote disconnect and reconnect capability.~~

(h) **Discretionary Meter Services.** An electric utility that operates in an area that offers customer choice must offer, as discretionary services in its tariff, installation of enhanced advanced meters and advanced meter features.

(1) A REP may request the electric utility to provide enhanced advanced meters, additional metering technology, or advanced meter features not specifically

offered in the electric utility's tariff, that are technically feasible, generally available in the market, and compatible with the electric utility's AMS.~~;~~

(2) The REP must pay the reasonable differential cost for the enhanced advanced meters or features and system changes required by the electric utility to offer those meters or features.

(3) Upon request by a REP, an electric utility must expeditiously provide a report to the REP that includes an evaluation of the cost and a schedule for providing the enhanced advanced meters or advanced meter features of interest to the REP. The REP must pay a reasonable discretionary services fee for this report. This discretionary services fee must be included in the electric utility's tariff.

(4) If an electric utility deploys enhanced advanced meters or advanced meter features not addressed in its tariff at the request of the REP, the electric utility must expeditiously apply to amend its tariff to specifically include the enhanced advanced meters or meter features that it agreed to deploy. Additional REPs may request the tariffed enhanced advanced meters or advanced meter features under the process described in this paragraph of this subsection.

~~(h) **Settlement.** It is the objective of this rule that ERCOT shall be able to use 15-minute meter information from advanced metering systems for wholesale settlement, not later than January 31, 2010.~~

(i) **Tariff.** All ~~non-standard,~~ discretionary AMS features offered by the electric utility must ~~shall~~ be described in the electric utility's tariff.

(j) **Access to meter data.**

(1) An electric utility must ~~shall~~ provide a customer, the customer's REP of record, and other entities authorized by the customer read-only access to the customer's advanced meter data, including meter data used to calculate charges for service, historical load data, and any other proprietary customer information. The access must ~~shall~~ be convenient and secure, and the data must ~~shall~~ be made available no later than the day after it was created.

(2) The requirement to provide access to the data begins when the electric utility has installed 2,000 advanced meters for residential and non-residential customers. If an electric utility has already installed 2,000 advanced meters by the effective date of this section, the electric utility must ~~shall~~ provide access to the data in the timeframe approved by the commission in either the deployment plan ~~Deployment Plan~~ or request for surcharge proceeding. If only a notice ~~Notice~~ of deployment ~~Deployment~~ has been filed, access to the data must ~~shall~~ begin no later than six months from the filing of the notice ~~Notice~~ of deployment ~~Deployment~~ with the commission.

(3) An electric utility's or group of electric utilities' web portal must ~~shall~~ use appropriate and reasonable ~~industry~~ standards and methods to provide ~~for providing~~ secure access for the customer, ~~and~~ the customer's REP of record, and entities authorized by the customer ~~access~~ to the meter data. The electric utility must ~~shall~~ have an independent security audit conducted within one year of providing that ~~the mechanism for customer and REP~~ access to meter data. The

electric utility must ~~conducted within one year of initiating such access and~~ promptly report the audit results to the commission.

(4) The independent organization, regional transmission organization, or regional reliability entity must ~~shall~~ have access to information that is required for wholesale settlement, load profiling, load research, and reliability purposes.

~~(5) A customer may authorize its data to be available to an entity other than its REP.~~

(k) **Cost recovery for deployment of AMS.**

(1) **Recovery Method.** The commission will ~~shall~~ establish a nonbypassable surcharge for an electric utility to recover reasonable and necessary costs incurred in deploying AMS to residential customers and nonresidential customers other than those required by the independent system operator to have an interval data recorder meter. The surcharge must ~~shall~~ not be established until after a detailed deployment plan ~~Deployment Plan~~ is filed under ~~pursuant to~~ subsection (d) of this section. In addition, the surcharge must ~~shall~~ not ultimately recover more than the AMS costs that are spent, reasonable and necessary, and fully allocated, but may include estimated costs that will ~~shall~~ be reconciled pursuant to paragraph (6) of this subsection. As indicated by the definition of AMS in subsection (c)(2) of this section, the costs for facilities that do not perform the functions and have the features specified in this section must ~~shall~~ not be included in the surcharge provided for by this subsection unless an electric utility has received a waiver under ~~pursuant to~~ subsection (g)(2)~~(g)(3)~~ of this section. The costs of providing AMS services include those costs of AMS installed as part of a pilot program

under ~~pursuant to~~ this section. Costs of providing AMS for a particular customer class must ~~shall~~ be surcharged only to customers in that customer class.

(2) **Carrying Costs.** The annualized carrying-cost rate to be applied to the unamortized balance of the AMS capital costs must ~~shall~~ be the electric utility's authorized weighted-average cost of capital (WACC). If the commission has not approved a WACC for the electric utility within the last four years, the commission may set a new WACC to apply to the unamortized balance of the AMS capital costs. In each subsequent rate proceeding in which the commission resets the electric utility's WACC, the carrying-charge rate that is applied to the unamortized balance of the utility's AMS costs must ~~shall~~ be correspondingly adjusted to reflect the new authorized WACC.

(3) **Surcharge Proceeding.** In the request for surcharge proceeding, ~~an electric utility may propose a surcharge methodology, but~~ the commission will set the surcharge based on ~~prefers the stability of~~ a levelized amount, and an amortization period ~~ranging from five to seven years, depending~~ based on the useful life of the AMS~~meter~~. The commission may set the surcharge to reflect a deployment of advanced meters that is up to one-third of the electric utility's total meters over each calendar year, regardless of the rate of actual AMS deployment. The actual or expected net operating cost savings from AMS deployment, to the extent that the operating costs are not reflected in base rates, may be considered in setting the surcharge. If an electric utility that requests a surcharge does not have an approved deployment plan~~Deployment Plan~~, the commission in the surcharge proceeding may reconcile the costs that the electric utility already spent on AMS

in accordance with paragraph (6) of this subsection and may approve a deployment plan~~Deployment Plan~~.

(4) **General Base Rate Proceeding while Surcharge is in Effect.** If the commission conducts a general base rate proceeding while a surcharge under this section is in effect, then the commission will ~~shall~~ include the reasonable and necessary costs of installed AMS equipment in the base rates and decrease the surcharge accordingly, and permit reasonable recovery of any non-AMS metering equipment that has not yet been fully depreciated but has been replaced by the equipment installed under an approved deployment plan~~Deployment Plan~~.

(5) **Annual Reports.** An electric utility must ~~shall~~ file annual reports with the commission updating the cost information used in setting the surcharge. The annual reports must ~~shall~~ include the actual costs spent to date in the deployment of AMS and the actual net operating cost savings from AMS deployment and how those numbers compare to the projections used to set the surcharge. During the annual report process, an electric utility may apply to update its surcharge, and the commission may set a schedule for such applications. For a levelized surcharge, the commission may alter the length of the surcharge collection period based on review of information concerning changes in deployment costs or operating costs savings in the annual report or changes in WACC. An annual report filed with the commission will ~~shall~~ not be a ratemaking proceeding, but an application by the electric utility to update the surcharge must ~~shall~~ be a ratemaking proceeding.

(6) **Reconciliation Proceeding.** All costs recovered through the surcharge must ~~shall~~ be reviewed in a reconciliation proceeding on a schedule to be determined by the

commission. Not~~h~~withstanding the preceding sentence, the electric utility may request multiple reconciliation proceedings, but no more frequently than once every three years. There is a presumption that costs spent in accordance with a deployment plan ~~Deployment Plan~~ or amended deployment plan ~~Deployment Plan~~ approved by the commission are reasonable and necessary. Any costs recovered through the surcharge that are found in a reconciliation proceeding not to have been spent or properly allocated, or not to be reasonable and necessary, must ~~shall~~ be refunded to electric utility's customers. In addition, the commission will ~~shall~~ make a final determination of the net operating cost savings from AMS deployment used to reduce the amount of costs that ultimately can be recovered through the surcharge. Accrual of interest on any refunded or surcharged amounts resulting from the reconciliation must ~~shall~~ be at the electric utility's WACC and must ~~shall~~ begin at the time the under or over recovery occurred.

(7) **Cross-subsidization and fees.** The electric utility must ~~shall~~ account for its costs in a manner that ensures ~~that~~ there is no inappropriate cost allocation, cost recovery, or cost assignment that would cause cross-subsidization between utility activities and non-utility activities. The electric utility shall not charge a disconnection or reconnection fee that was approved by the commission prior to the effective date of this rule, for a disconnection or reconnection that is effectuated using the remote disconnection or connection capability of an advanced meter.

~~(l) **Time of Use Schedule.** Commission approval of a time of use schedule (“TOUS”) pursuant to ERCOT protocols is not necessary prior to implementation of the new TOUS~~.

§25.133. Non-Standard Metering Service.

(a) **Purpose.** This section allows a customer ~~whose standard meter is an advanced meter~~ to choose to receive electric service through a non-standard meter from an electric utility that has deployed or is requesting to deploy advanced meters~~,~~ under a commission-approved deployment plan or notice of deployment and authorizes the electric utility ~~a transmission and distribution utility (TDU)~~ to assess fees to recover the costs associated with this section from a customer who elects to receive electric service through a non-standard~~such a~~ meter.

(b) **Applicability.** This section is applicable to an electric utility, including a transmission and distribution utility, that has deployed or is requesting to deploy advanced meters under a commission-approved deployment plan or notice of deployment. Any requirement in this section that relates to retail electric providers (REPs) is applicable only to REPs and electric utilities that operate in areas open to customer choice.

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

(1) Advanced meter -- As defined in §25.130 of this title (relating to Advanced Metering).

(2) Non-standard meter -- A meter that does not function as an advanced meter.

(3) Non-standard metering service -- Provision of electric service through a non-standard meter from an electric utility that has deployed or is requesting to deploy

advanced meters under a commission-approved deployment plan or notice of deployment.

(d)~~(c)~~ **Initiation and termination of non-standard metering service.**

(1) **Initiation of non-standard metering service**. An electric utility that has deployed or is requesting to deploy advanced meters under a commission-approved deployment plan or notice of deployment must offer non-standard metering service to customers.

(A) An electric utility filing a deployment plan or notice of deployment under §25.130 of this title after the effective date of this section must include non-standard metering service as a part of the plan or notice. ~~This subparagraph applies to a TDU that, on the date that the TDU begins offering non-standard metering service pursuant to subsection (g) of this section, has completed deployment of advanced meters except for customers for whom the TDU did not install advanced meters because of the requests of the customers. The TDU shall serve on such a customer by certified mail return receipt requested notice consistent with subparagraph (D) of this paragraph within 30 days of the date that the TDU begins offering non-standard metering service pursuant to subsection (g) of this section.~~

(i) Within 30 days of the date of commission approval of an electric utility's deployment plan or the filing of a notice of deployment, the electric utility must provide information on its website that describes its non-standard metering service, the process under this section to request non-standard metering service, and all the costs associated with the service.

(ii) An electric utility must provide a statement that non-standard metering service is available and provide a hyperlink to the information required under clause (i) of this subparagraph in all notices and messages delivered to a customer relating to the deployment date of advanced meters in the customer's geographic area.

~~(B) This subparagraph applies to a TDU that has not completed deployment of advanced meters.~~

~~(i) This clause applies to a customer for whom the TDU has not, on the date that the TDU begins offering non-standard metering service pursuant to subsection (g) of this section, installed an advanced meter because of the request of the customer. The TDU shall serve on such a customer by certified mail return receipt requested notice consistent with subparagraph (D) of this paragraph within 30 days of the date that the TDU begins offering non-standard metering service pursuant to subsection (g) of this section.~~

~~(ii) This clause applies to a customer for whom, after the date that the TDU begins offering non-standard metering service pursuant to subsection (g) of this section, the TDU attempts to install an~~

~~advanced meter as part of its advanced meter deployment plan but the customer requests non-standard metering service. The TDU shall promptly serve on such a customer by certified mail return receipt requested notice consistent with subparagraph (D) of this paragraph.~~

(B)~~(C)~~ ~~For circumstances not addressed by subparagraph (A) or (B) of this paragraph in which a customer requests from the~~ An electric utility~~TDU non-standard metering service, the TDU~~ must ~~shall~~ provide notice to a customer consistent with subparagraph (C) ~~(D)~~ of this paragraph within seven days of the customer's request for non-standard metering service, using an appropriate means of service.

(C)~~(D)~~ ~~Pursuant to subparagraphs (A)-(C) of this paragraph,~~ An ~~a~~ electric utility ~~TDU~~ must ~~shall~~ notify a customer that requests non-standard metering service of the following through a written acknowledgement.

(i) The customer will be required to pay the costs associated with the initiation of non-standard metering service and the ongoing costs associated with the manual reading of the meter, and other fees and charges that may be assessed by the electric utility ~~TDU~~ that are associated with the non-standard metering service;

(ii) The current one-time fees and monthly fee for non-standard metering service;

(iii) The customer may be required to wait up to 45 days to switch the customer's ~~retail electric provider (~~REP~~)~~ of record;~~,~~

(iv) The customer ~~and~~ may experience longer restoration times in case of a service interruption or outage;

(v)~~(iv)~~ The customer may be required by the customer's REP of record to choose a different product or service before initiation of the non-standard metering service, subject to any applicable charges or fees required under the customer's existing contract, if the customer is currently enrolled in a product or service that relies on an advanced meter; and

(vi)~~(v)~~ For a customer that does not currently have an advanced meter, the date (60 days after service of the notice) by which the customer must provide a signed, written acknowledgement and payment of the one-time fee to the electric utility ~~TDU~~ prescribed by subsection (f)~~(e)~~(3) of this section. If the signed, written acknowledgement and payment are not received within 60 days, the electric utility ~~TDU~~ will install an advanced meter on the customer's premises.

(D)~~(E)~~ The electric utility ~~TDU~~ must ~~shall~~ retain the signed, written acknowledgement for at least two years after the non-standard meter is removed from the premises. The commission may adopt a form for the written acknowledgement.

(E)~~(F)~~ An ~~A~~ electric utility ~~TDU~~ must ~~shall~~ offer non-standard metering through the following means:

(i) disabling communications technology in an advanced meter if feasible;

(ii) if applicable, allowing the customer to continue to receive metering service using the existing meter if the electric utility ~~TDU~~ determines that it meets applicable accuracy standards;

(iii) if commercially available, an analog meter that meets applicable meter accuracy standards; and

(iv) a digital, non-communicating meter.

(F)~~(G)~~ The electric utility ~~TDU~~ must ~~shall~~ not initiate the process to provide non-standard metering service before it has received the customer's payment and signed, written acknowledgement. The electric utility ~~TDU~~ must ~~shall~~ initiate the approved standard market process to notify the customer's REP of record within three days of the electric utility's ~~TDU's~~ receipt of the customer's payment and signed, written acknowledgement. Within 30 days of receipt of the payment of the one-time fee and the signed written acknowledgement from the customer, the electric utility~~TDU~~, using the approved standard market process, must ~~shall~~ notify the customer's REP of record of the date the non-standard metering service was initiated.

(2) **Termination of non-standard metering service**. A customer receiving non-standard metering service may terminate that service by notifying the customer's electric utility~~TDU~~. The customer will ~~shall~~ remain responsible for all costs related to non-standard metering service.

(e)~~(d)~~ **Other electric utility~~TDU~~ obligations.**

(1) When an ~~a~~ electric utility ~~TDU~~ completes a move-out transaction for a customer who was receiving non-standard metering service, the electric utility ~~TDU~~ must ~~shall~~ install ~~and/~~or activate an advanced meter at the premises.

(2) An ~~A~~ electric utility ~~TDU~~ must ~~shall~~ read a non-standard meter monthly. In order for the electric utility ~~TDU~~ to maintain a non-standard meter at the customer's premises, the customer must provide the electric utility ~~TDU~~ with sufficient access to properly operate and maintain the meter, including reading and testing the meter.

(f)~~(e)~~ **Cost recovery and compliance tariffs.** All costs incurred by an ~~a~~ electric utility ~~TDU~~ to implement this section must ~~shall~~ be borne only by customers who choose non-standard metering service. A customer receiving non-standard metering service must ~~shall~~ be charged a one-time fee and a recurring monthly fee.

(1) ~~Not later than 25 days after the effective date of this section, each~~ An electric utility's application for approval of its non-standard metering service tariff or amended tariff must be~~TDU must shall file a compliance tariff that is~~ fully supported with testimony and documentation. The ~~compliance tariff~~ application must ~~shall~~ include one-time fees and a monthly fee for non-standard metering service and must ~~shall~~ also include the fees for other discretionary services performed by the electric utility ~~TDU~~ that are affected by the customer's selection of non-standard metering service. The commission will allow the electric utility~~Each electric utility TDU must shall be allowed~~ to recover the reasonable

rate case expenses that it incurs under this paragraph~~subsection~~ as part of the one-time fee, the monthly fee, or both. The application~~compliance tariff filing~~ must ~~shall~~ describe the extent to which the back-office costs that are new and fixed vary depending on the number of customers receiving non-standard metering service. Unless otherwise ordered, the electric utility ~~TDU~~ must ~~shall~~ serve notice of the approved rates and the effective date of the approved rates within five working days of the filing of the commission's final order~~presiding officer's final decision,~~ to REPs that are authorized by the registration agent to provide service in the electric utility's ~~TDU's distribution~~ service area. Notice to REPs under this paragraph may be served by email and~~, consistent with subsection (g) of this section,~~ must ~~shall~~ be served at least 45 days before the effective date of the rates~~electric utility TDU begins offering non-standard metering service~~.

~~(2) An electric utility A TDU may apply to change the fees approved pursuant to paragraph (1) of this subsection. The application must be fully supported with testimony and documentation. Each electric utility TDU will shall be allowed to recover the reasonable rate case expenses that it incurs under this subsection as part of the one-time fee, the monthly fee, or both. Unless otherwise ordered, the electric utility TDU must shall serve notice of the approved rates and the effective date of the approved rates within five working days of the presiding officer's final decision, to REPs that are authorized by the registration agent to provide service in the electric utility's TDU's distribution service area. Notice under this paragraph may be served by email and, if possible, must shall be served at least 45 days before the effective date of the rates.~~

(2)~~(3)~~ An electric utility ~~A TDU~~ must ~~shall~~ have a single recurring monthly fee for non-standard metering service and several one-time fees, one of which must ~~shall~~ apply to the customer depending on the customer's circumstances. A one-time fee must ~~shall~~ be charged to a customer that does not have an advanced meter at the customer's premises and will continue receiving metering service through the meter currently at the premises. For a customer that currently has an advanced meter at the premises, the fee will ~~shall~~ vary depending on the type of meter that is installed to provide non-standard metering service, and the fee must ~~shall~~ include the cost to remove the advanced meter and subsequently re-install an advanced meter once non-standard metering service is terminated. The one-time fee must ~~shall~~ recover costs to initiate non-standard metering service. The monthly fee must ~~shall~~ recover ongoing costs to provide non-standard metering service, including costs for meter reading and billing. Fixed costs not related to the initiation of non-standard metering service may be allocated between the one-time and monthly fees~~,~~ and recovered through the monthly fee over a shortened period of time.

(g)~~(f)~~ **Retail electric product compatibility.** After receipt of the notice prescribed by subsection (d)~~(e)~~(1)(C)~~(D)~~ of this section, if the customer's current product is not compatible with non-standard metering service, the customer's REP of record must ~~shall~~ work with the customer to either promptly transition the customer to a product that is compatible with non-standard metering service or transfer the customer to another REP, subject to any applicable charges or fees required under the customer's existing contract.

If the customer is unresponsive, the customer’s REP of record may transition the customer without the customer's affirmative consent to a market-based, month-to-month product that is compatible with non-standard metering service. Alternatively, if the customer is unresponsive, the customer’s REP of record may transfer the customer to another REP under ~~pursuant to~~ §25.493 (relating to Acquisition and Transfer of Customers from One Retail Electric Provider or Another) so long as the new REP serves the customer using a market-based, month-to-month product with a rate (excluding charges for non-standard metering service or other discretionary services) no higher than one of the tests prescribed by §25.498(c)(15)(A)-(C) of this title (relating to Prepaid Service). The customer’s REP of record must ~~shall~~ promptly provide the customer notice that the customer has been transferred to a new product and, if applicable, to a new REP, and must ~~shall~~ also promptly provide the new Terms of Service and Electricity Facts Label.

~~(g) **Implementation**. A TDU shall begin offering non-standard metering service pursuant to this section the later of 160 days from the effective date of this section or 45 days after the notice to REPs prescribed by subsection (e)(1) of this section.~~

§25.5. Definitions.

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

(1) – (114) (No Change.)

(115) **Retail electric provider (REP) of record** -- The REP assigned to the electric service identifier (ESI ID) in ERCOT's database. There can be no more than one REP of record assigned to an ESI ID at any specific point in time.

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

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

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

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

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

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

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

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

(124)~~(123)~~ **Stranded cost --** The positive excess of the net book value of generation assets over the market value of the assets, taking into account all of the electric utility's generation assets, any above-market purchased power costs, and any deferred debit related to a utility's discontinuance of the application of Statement of Financial Accounting Standards Number 71 ("Accounting for the Effect of Certain Types of Regulation") for generation-related assets if required by the provisions of the Public Utility Regulatory Act (PURA), Chapter 39. For purposes of PURA §39.262, book value shall be established as of December 31, 2001, or the date a market value is established through a market valuation method under PURA §39.262(h), whichever is earlier, and shall include stranded costs incurred under PURA §39.263.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

This agency certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

ISSUED IN AUSTIN, TEXAS ON THE 14TH DAY OF NOVEMBER 2019 BY THE PUBLIC UTILITY COMMISSION OF TEXAS
ANDREA GONZALEZ

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