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PROJECT NO. 55250

TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLANS	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

PROPOSAL FOR PUBLICATION OF NEW 16 TAC §25.62
AS APPROVED AT THE SEPTEMBER 14, 2023 OPEN MEETING

The Public Utility Commission of Texas (commission) proposes new 16 Texas Administrative Code (TAC) §25.62 relating to Transmission and Distribution System Resiliency Plans. The proposed rule will implement Public Utility Regulatory Act (PURA) §38.078 as enacted by House Bill 2555 during the Texas 88th legislative session (R.S). The proposed rule establishes the requirements and procedures for an electric utility to submit a resiliency plan to enhance the resiliency of its transmission and distribution systems.

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 rule is in effect, the following statements will apply:

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

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

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

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

(5) the proposed rule will create a new regulation;

(6) the proposed rule will not expand, limit, or repeal an existing regulation;

(7) the proposed rule will not change the number of individuals subject to the rule's applicability; and

(8) the proposed rule 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 rule. 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 rule 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

Chris Roelse, Director, Engineering, Infrastructure Division, has determined that for the first five-year period the proposed rule is 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 sections.

Public Benefits

Mr. Roelse has determined that for each year of the first five years the proposed section is in effect the anticipated public benefit of enforcing the section will be more resilient electric transmission and distribution systems that can withstand weather related and other emergency events to improve overall electric service quality and reliability for customers. There will be no adverse economic effect on small businesses or micro-businesses as a result of enforcing this section.

Local Employment Impact Statement

For each year of the first five years the proposed section is 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 commission is expressly excluded under §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. The request for a public hearing must be received by October 6, 2023. If a request for public hearing is received, commission staff will file in this project a notice of hearing.

Public Comments

Interested persons may file comments electronically through the interchange on the commission's website. Comments must be filed by October 6, 2023. Comments should be organized in a manner consistent with the organization of the proposed rules. 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 rules on adoption. All comments should refer to Project Number 55250.

Each set of comments should include a standalone executive summary as the first page of the filing. This executive summary must be clearly labeled with the submitting entity's name and should list each substantive recommendation made in the comments. Citations to detailed discussion in the comments are permissible but not required.

Statutory Authority

The rule is adopted under PURA §14.002, which provides the commission with the authority to adopt and enforce rules reasonably required in the exercise of its powers and jurisdiction. The new rule is also adopted under PURA §38.078 which allows electric utilities to submit to the commission, plans to enhance transmission and distribution system resiliency.

Cross Reference to Statute: Public Utility Regulatory Act §14.002 and §38.078

§25.62. Transmission and Distribution System Resiliency Plans.

(a) Applicability. This section applies to an electric utility that owns and operates a transmission and distribution system.

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

(1) Distribution invested capital -- The parts of the electric utility's invested capital that are categorized as distribution plant and, once they are placed into service, are properly recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 352, 353, and 360 through 374. Distribution invested capital includes only costs: for plant that has been placed into service or will be placed into service prior to rates going into effect; that comply with Public Utility Regulatory Act (PURA), including §36.053 and §36.058; and that are prudent, reasonable, and necessary. Distribution invested capital does not include: generation-related costs; transmission-related costs, including costs recovered through rates set pursuant to §25.192 of this title (relating to Transmission Service Rates), §25.193 of this title (relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)), or §25.239 of this title (relating to Transmission Cost Recovery Factor for Certain Electric Utilities); indirect corporate costs; capitalized operations and maintenance expenses; and distribution invested capital recovered through a separate rate, including a surcharge, tracker, rider, or other mechanism.

(2) **Resiliency cost recovery rider (RCRR) billing determinant** -- Each rate class's annual billing determinant (kilowatt-hour, kilowatt, or kilovolt-ampere) for the most recent 12 months ending no earlier than 90 days prior to an application for a Resiliency Cost Recovery Rider, weather-normalized and adjusted to reflect the number of customers at the end of the period.

(3) **Resiliency event** -- a low frequency, high impact event that, if not mitigated, poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems. A resiliency event is not primarily associated with resource adequacy or an electric utility's ability to deliver power to load under normal operating conditions.

(4) **Resiliency-related distribution invested capital** -- Distribution invested capital associated with a resiliency plan approved under this section that will be placed into service before or at the time the associated rates become effective under this section, and that are not otherwise included in a utility's rates.

(5) **Resiliency-related net distribution invested capital** -- Resiliency-related invested capital that is adjusted for accumulated depreciation and any changes in accumulated deferred federal income taxes, including changes to excess accumulated deferred federal income taxes, associated with all resiliency-related distribution invested capital included in the electric utility's RCRR.

(6) **Weather-normalized** -- Adjusted for normal weather using weather data for the most recent ten-year period prior to the year from which the RCRR billing determinants are derived.

(c) **Resiliency Plan.** An electric utility may file a plan to mitigate the risks posed by resiliency events to its transmission and distributions systems. A resiliency plan may be updated, but the updated plan must not take effect earlier than three years from the date of approval of the electric utility's most recently approved resiliency plan.

(1) **Resiliency measures.** A resiliency plan is comprised of one or more measures designed to mitigate the risks posed to the electric utility's transmission and distribution systems by resiliency events, as described in subsection (d) of this section. Each measure must utilize one or more of the following methods:

(A) hardening electric transmission and distribution facilities;

(B) modernizing electric transmission and distribution facilities;

(C) undergrounding certain electric distribution lines;

(D) lightning mitigation measures;

(E) flood mitigation measures;

(F) information technology;

(G) cybersecurity measures;

(H) physical security measures;

(I) vegetation management; or

(J) wildfire mitigation and response.

(2) **Contents of the resiliency plan.** The resiliency plan must be organized by measure, including a description of the activities, actions, standards, services, procedures, practices, structures, and equipment associated with each measure.

(A) **Chosen resiliency measures and programs.** The resiliency plan must identify, for each measure, one or more resiliency events that the measure is intended to mitigate.

(i) The resiliency plan must explain the electric utility's prioritization of the identified resiliency event and, if applicable, the prioritization of the particular geographic area, system, or facilities where the measure will be implemented.

(ii) The resiliency plan must include evidence of the effectiveness of the measure in preventing, responding to, or recovering from the identified resiliency event. The commission will give greater weight to evidence that is quantitative, performance-based, or provided by an independent entity with relevant expertise.

(iii) A resiliency plan must explain the benefits of the resiliency measures including but not limited to reduced system restoration costs, reduction in the frequency or duration of outages for customers. and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations.

(iv) The electric utility should identify if a resiliency measure is a coordinated effort with federal, state, or local government programs and funding opportunities.

(v) The resiliency plan must explain the selection of each measure over any reasonable and readily-identifiable alternatives. The resiliency plan must contain sufficient analysis and evidence, such as cost or performance comparisons, to support the selection of each measure.

In selecting between measures, whether a measure would support the plan's systematic approach may be considered.

(B) **Resiliency events.**

(i) A resiliency plan must define each type of resiliency event the plan is designed to mitigate. A resiliency event may be defined using an established definition (e.g., a hurricane) or a plan- or measure-specific definition based on the risks posed by that type of event to the electric utility's systems (e.g., flooding of a specified depth). Each type of resiliency event must be defined with sufficient detail to allow the electric utility or commission to determine whether an actual set of circumstances qualifies as a resiliency event of that type.

(ii) If appropriate, one or more magnitude thresholds must be included in the definition of a resiliency event type based on the risks posed to the electric utility's systems by that type of event. A resiliency plan may establish multiple magnitude thresholds for a single type of resiliency event (e.g., categories of hurricanes) when necessary to conduct a more granular analysis of the risks posed by the event and the options available to address it.

(iii) The resiliency plan must include a description of the system characteristics that make the electric utility's transmission and distribution systems susceptible to each identified resiliency event type. The resiliency plan must explain the electric utility's experience with, if applicable, and forecasted risk of the identified event type, including whether the forecasted risk is specific to a particular system or geographic area.

(iv) A resiliency plan must provide sufficient evidence to support the presence of and risk posed by each identified resiliency event including historical evidence of the frequency and magnitude of each event type. In assessing the presence and risk posed by each resiliency event, the commission will give great weight to any studies conducted by an independent system operator or independent entity with relevant expertise.

(C) **Evaluation metric or criteria**. Each measure in the resiliency plan must include a proposed metric, or criteria for evaluating the effectiveness of that measure in mitigating the associated resiliency event.

(i) The resiliency plan must include documentation necessary to support the use of the selected evaluation metric or criteria.

(ii) For an evaluation metric or criteria that is not quantitative, the resiliency plan must explain why quantitative evaluation of the effectiveness of that measure is not possible.

(iii) The resiliency plan must also include an estimate of the expected effectiveness of each measure using the selected evaluation metric or criteria.

(D) If a resiliency plan includes measures that are similar to other existing programs or measures otherwise required by law, such as a storm hardening plan under §25.95 of this title (relating to Electric Utility Infrastructure Storm Hardening) or a vegetation management plan under §25.96 of this title (relating to Vegetation Management) the electric utility must distinguish the measures in the resiliency plan from the other program's measures and, if appropriate, explain how the related items work in conjunction with one another.

(E) A resiliency plan must be implemented using a systematic approach over a period of at least three years. The resiliency plan must explain this systematic approach and provide implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, and an estimated timeline for completion. the resiliency plan should identify relevant cost drivers (e.g., line miles, frequency of inspections, frequency of trim cycles, etc.) that would affect the estimates.

(F) The resiliency plan must include an executive summary of the plan objectives, event to be mitigated, measures taken, and metrics used to evaluate effectiveness, cost and benefits, and how the overall plan is in the public interest.

(3) An electric utility may designate portions of the resiliency plan as critical energy infrastructure information, as defined by applicable law, and file such portions confidentially.

(d) Commission processing of resiliency plan

(1) **Notice and intervention deadline.** The electric utility must provide notice of its filed resiliency plan, including the docket number assigned to the resiliency plan and the deadline for intervention, in accordance with this paragraph. The notice must be provided by first class mail or, if the recipient has agreed to receive electronic notifications, electronic mail. The notice must be mailed the same day the application is filed. The intervention deadline is 20 days after the filing of the application. The notice must be delivered to:

(A) all municipalities in the electric utility's service area that have retained original jurisdiction;

(B) all parties in the electric utility's last base rate proceeding; and

(C) the Office of Public Utility Counsel. Notice delivered to the Office of Public Utility Counsel must include a complete copy of the resiliency plan.

(2) **Sufficiency of resiliency plan.** An application is sufficient if it includes the information required by subsection (c) of this section and the electric utility has filed proof that notice has been provided in accordance with this subsection. A motion to find a resiliency plan materially deficient must be filed no later than 20 calendar days after the resiliency plan is filed. The motion must specify the nature of the deficiency and the relevant portions of the resiliency plan, and cite the particular requirement with which the resiliency plan is alleged not to comply. The electric utility's response to a motion to find a resiliency plan materially deficient must be filed no later than five working days after such motion is received. A motion to find an amended resiliency plan deficient, when the amendment is filed

in response to an order concluding that material deficiencies exist in the resiliency plan, must be filed no later than five working days after the amended resiliency plan is filed. If the presiding officer has not issued a written order within 35 calendar days of the filing of the resiliency plan, or 25 calendar days of the filing of an amended resiliency plan, concluding that material deficiencies exist in the resiliency plan, the resiliency plan is deemed sufficient.

(3) The commission will approve, modify, or deny a resiliency plan not later than 180 days after a complete resiliency plan is filed. A resiliency plan is complete if it is deemed sufficient in accordance with this subsection. The presiding officer must establish a procedural schedule that will enable the commission to approve, modify, or deny the plan not later than 180 days after a complete plan is filed. If the resiliency plan is determined to be materially deficient, the presiding officer must toll the 180-day deadline until a complete application is filed.

(A) The commission's denial of a resiliency plan is not a finding on the prudence or imprudence of a measure or estimated cost in the resiliency plan. Upon denial of a resiliency plan, an electric utility may file a revised resiliency plan for review and approval by the commission.

(B) If the commission modifies a resiliency plan, the electric utility may withdraw the resiliency plan without prejudice or propose alternative modifications for the commission's consideration. The deadline for withdrawing a modified resiliency plan or proposing alternative modifications is the deadline for a motion for rehearing under §22.264 of this title (relating to Rehearing).

(4) **Commission review of resiliency plan.** The commission will approve or modify an electric utility's proposed resiliency plan if it determines that approving or modifying the plan is in the public interest. In determining the public interest, the commission may consider:

(A) the verifiability and severity of the resiliency risks posed by the resiliency events the resiliency plan is designed to address;

(B) the extent to which the plan will enhance resiliency of the electric utility's system, mitigate system restoration costs, reduce the frequency or duration of outages, and improve overall service reliability for customers;

(C) the extent to which the resiliency plan prioritizes areas of lower performance;

(D) the extent to which the resiliency plan prioritizes critical load as defined in §25.52 of this title (relating to Reliability and Continuity of Service);

(E) the estimated time and costs of implementing the measures proposed in the resiliency plan;

(F) whether there are more efficient or cost-effective means of addressing the resiliency events addressed by the resiliency plan; and

(G) other factors deemed relevant by the commission.

(e) **Good cause exception.** An electric utility must implement each measure in its most recently approved resiliency plan unless the commission grants a good cause exception to implementing one or more measure in the plan. The commission will grant a good cause exception if the electric utility demonstrates that operational needs, business needs, financial conditions, or supply chain or labor conditions dictate the exception. The commission may also grant a good cause exception allowing the electric utility to delay implementation of one or more measures in its resiliency plan if the electric utility has a pending application for a revised resiliency plan that addresses the same resiliency events.

(f) Resiliency Plan Cost Recovery. A utility may request cost recovery for costs associated with a resiliency plan approved under this section that are not otherwise included in the utility's rates.

(1) Resiliency Cost Recovery Rider. This paragraph provides a mechanism for an electric utility to request to recover certain resiliency-related costs through a resiliency cost recovery rider (RCRR) outside of a base-rate proceeding or a distribution cost recovery proceeding as part of a resiliency plan approved under this section, consistent with PURA §38.078(i).

(A) **RCRR Requirements.** The RCRR rate for each rate class, and any other terms or conditions related to those rates, will be specified in a rider to the utility's tariff.

(i) An electric utility must not have more than one RCRR.

(ii) An electric utility with an existing RCRR may apply to amend the RCRR to include additional costs associated with an updated resiliency plan under PURA §38.078(g).

(iii) Any RCRR established under this section may not take effect until all facilities with costs included in the RCRR begin providing service to the electric utility's customers.

(iv) As part of its next base-rate proceeding or distribution cost recovery factor proceeding for the electric utility, the electric utility may request to include its costs included in its RCRR in that proceeding and must request that RCRR rates be set to zero as of the effective date of rates resulting from that proceeding.

(B) **Calculation of RCRR Rates.** The RCRR rate for each rate class must be calculated according to the provisions of this subparagraph and subparagraphs (C) and (D) of this paragraph.

(i) The RCRR rate for each rate class will be calculated using the following formula:

$$RCRR_{CLASS} = RR_{CLASS} / BD_{C\text{-}CLASS}$$

(ii) The values of the terms used in this paragraph will be calculated as follows:

(I) $RR_{CLASS} = RR_{TOT} * ALLOC_{C\text{-}CLASS}$

(II) $RR_{TOT} = ((RNDC * ROR_{RC}) + RDDEPR + RNDCFIT + RDOT) - IDCCR$

(III) $ALLOC_{C\text{-}CLASS} =$

$ALLOC_{RC\text{-}CLASS} * (BD_{C\text{-}CLASS} / BD_{RC\text{-}CLASS}) / \Sigma (ALLOC_{RC\text{-}CLASS} * (BD_{C\text{-}CLASS} / BD_{RC\text{-}CLASS}))$

(IV) $IDCCR = \Sigma (DISTREV_{RC\text{-}CLASS} * \%GROWTH_{CLASS}) – DCRFLGA$

(V) $DISTREV_{RC\text{-}CLASS} = (DIC_{RC\text{-}CLASS} * ROR_{AT}) + DEPR_{RC\text{-}CLASS} + FIT_{RC\text{-}CLASS} + OT_{RC\text{-}CLASS}$, with the variables in this formula as defined in §25.239 of this title.

(VI) $\%GROWTH_{CLASS} = (BD_{C\text{-}CLASS} – BD_{RC\text{-}CLASS}) / BD_{RC\text{-}CLASS}$

(iii) The terms used in this paragraph represent or are defined as follows:

(I) **Descriptions of calculated values.**

(-a-) **$RCRR_{CLASS}$** -- RCRR rate for a rate class.

(-b-) **RR_{CLASS}** -- RCRR class revenue requirement.

(-c-) **RR_{TOT}** -- Total RCRR Texas retail revenue requirement.

(-d-) **$ALLOC_{C\text{-}CLASS}$** -- RCRR class allocation factor for a rate class.

(-e-) **IDCCR** -- Incremental distribution capital cost recovery.

(-f-) **$DISTREV_{RC\text{-}CLASS}$** -- Distribution Revenues by rate class based on Net Distribution Invested Capital from the last comprehensive base-rate proceeding.

(-g-) **$\%GROWTH_{CLASS}$** – Growth in billing determinants by class.

(II) **RCRR billing determinants and distribution investment values.**

(-a-) **$BD_{C\text{-}CLASS}$** -- RCRR billing determinants.

(-b-) **RNDC** -- Resiliency-related net distribution invested capital.

(-c-) **RDDEPR** -- Resiliency-related distribution invested capital depreciation expense.

(-d-) **RNDCFIT** -- Federal income tax expense associated with the return on the resiliency-related net distribution invested capital.

(-e-) **RDOT** -- Other tax expense associated with the resiliency-related distribution invested capital.

(III) **Baseline values.** The following values are based on those values used to establish rates in the electric utility's most recent base-rate proceeding or distribution cost recovery factor proceeding, or if an input to the RCRR calculation from the electric utility's last base-rate proceeding is not separately identified in that proceeding, it will be derived from information from that proceeding:

(-a-) **$BD_{RC\text{-}CLASS}$** -- Rate class billing determinants used to establish distribution base rates in the last base-rate proceeding. Energy-based billing determinants will be used for those rate classes that do not include any demand charges, and demand-based billing determinants will be used for those rate classes that include demand charges.

(-b-) **ROR_{RC}** -- After-tax rate of return approved by the commission in the electric utility's last base-rate proceeding.

(-c-) **$ALLOC_{RC\text{-}CLASS}$** -- Rate class allocation factor value determined under the provisions of subparagraph (C) of this paragraph.

(-d-) **DCRFLGA** -- The value of $\Sigma(DISTREV_{RC\text{-}CLASS} * \%GROWTH_{CLASS})$ in the most recent distribution cost recovery factor proceeding for the utility since its late base rate proceeding, or zero if there are no distribution cost recovery factor proceedings since the utility's last base rate proceeding.

(C) **Class allocation factors.** For calculating RCRR rates, the baseline rate-class allocation factors used to allocate distribution invested capital in the last base-rate proceeding will be used.

(D) **Customer classification.** For the purposes of establishing RCRR rates, customers will be classified according to the rate classes established in the electric utility's most recently completed base-rate proceeding.

(2) Resiliency Cost Recovery Factor. This paragraph provides a mechanism for an electric utility to request to recover certain resiliency-related costs deferred as a regulatory asset through a resiliency cost recovery factor (RCRF) rate as part of a transmission cost recovery factor proceeding under §25.239 of this title, consistent with PURA §38.078(k).

(A) Notwithstanding the existing requirements of §25.239 of this title, a utility eligible to request a transmission cost recovery factor under §25.239 of this title may, as part of an application under §25.239 of this title request to include RCRF rates calculated consistent with this paragraph in addition to the TCRF rates allowed under §25.239 of this title.

(B) RCRF rates established as part of a TCRF application under §25.239 of this title must be calculated in a manner identical to the RCRR rates described in paragraph (1) of this subsection, with the exception that the value of RRTOT must be equal to a reasonable annual amortization amount of the resiliency-related regulatory asset, less the value of IDCRR.

(C) Upon the establishment of an RCRF rate, the resiliency-related regulatory asset balance will be reduced at an annual rate by the annual amortization amount used to establish the RCRF rates.

(3) Distribution Cost Recovery Factor. This paragraph provides a mechanism for an electric utility to request to recover certain resiliency-related costs deferred as a regulatory asset as part of a distribution cost recovery factor proceeding under §25.234 of this title, consistent with PURA §38.078(k).

(A) Notwithstanding the existing requirements of §25.234 of this title, a utility eligible to request a distribution cost recovery factor under §25.234 of this title may, as part of an application under §25.234 of this title, request to include resiliency-related costs deferred as a regulatory asset in its DCRF rates.

(B) DCRF rates established consistent with this paragraph must be calculated in a manner identical to the DCRF rates described in §25.234 of this title, with the exception that the DCRF rate for each rate class must be calculated using the following formula:

$[((DIC_C - DIC_{RC}) * ROR_{AT}) + (DEPR_C – DEPR_{RC}) + (FIT_C – FIT_{RC}) + (OT_C – OT_{RC}) + RAMORT – \Sigma\ (DISTREV_{RC\text{-}CLASS} * \%GROWTH_{CLASS})] * ALLOC_{CLASS} / BD_{C\text{-}CLASS}$

Where the value of RAMORT must be equal to a reasonable annual amortization amount of the resiliency-related regulatory asset.

(C) Upon the establishment of an DCRF rate under this paragraph, the resiliency-related regulatory asset balance will be reduced at an annual rate by the value of RAMORT.

(4) Reconciliation.

(A) Resiliency-related amounts recovered through rates approved under this subsection are subject to reconciliation in the first base-rate proceeding for the electric utility that is filed after the effective date of the rates. As part of the reconciliation, the commission will determine if the resiliency-related costs are reasonable, necessary, and prudent.

(B) Any amounts recovered through rates approved under this subsection that are found to have been unreasonable, unnecessary, or imprudent, plus the corresponding return and taxes, must be refunded with carrying costs. Carrying costs will be determined as follows:

(i) For the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the electric utility's base rates set in the base-rate proceeding in which the costs are reconciled, carrying costs will accrue monthly and will be calculated using an effective monthly interest rate based on the same rate of return that was applied to the resiliency costs included in rates.

(ii) For the time period beginning with the effective date of the electric utility's rates set in the base-rate proceeding in which the costs are reconciled, carrying costs will accrue monthly and will be calculated using an effective monthly interest rate based on the electric utility's rate of return authorized in that base-rate proceeding.

(g) Reporting requirements. An electric utility with a commission-approved resiliency plan must file an annual resiliency plan report by May 1 of each year. The annual resiliency plan report must include the following information:

(1) until the resiliency plan is fully implemented, an implementation status update consisting of:

(A) a list of each resiliency plan measure completed in the prior calendar year, and the actual capital costs and operations and maintenance expenses incurred in the prior year attributable to each measure;

(B) a list of each resiliency plan measure scheduled for completion in the upcoming year, and an estimate of capital costs and operations and maintenance expenses for each resiliency plan measure scheduled for completion in the upcoming calendar year; and

(C) an explanation for any material changes in the implementation timeline or costs associated with implementing the resiliency plan; and

(2) until the third anniversary of the plan being fully implemented, a resiliency benefit update consisting of:

(A) a report on the occurrence of any resiliency events the resiliency plan or a previously-implemented resiliency plan was intended to address, including a comparison of the frequency and magnitude of these events with any projections contained in the resiliency plan or previously-implemented resiliency plan;

(B) an evaluation of the effectiveness of each implemented resiliency plan measure in addressing any resiliency events that measure was implemented to address. This evaluation must include an analysis using the metric or criteria contained in the resiliency plan for that measure, and a comparison of the measure's actual effectiveness with its projected effectiveness.

(C) an update on the expected impact of implemented resiliency plan measures on system restoration costs, reduction in the frequency or duration of outages for customers at the location for which a resiliency plan was implemented, and any improvement in the overall service reliability for customers. An electric utility may report realized benefits and SAIDI, SAIFI, and CAIDI statistics at the feeder level when possible. The index statistics must include all interruption classifications and must display the number of critical and chronic customers on each feeder.

(3) An electric utility is required to maintain records associated with the information referred to in this subsection. Upon request by commission staff an electric utility must provide any additional information and updates on the status of the resiliency plan submitted.

This agency hereby 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 14 DAY OF SEPTEMBER 2023 BY THE PUBLIC UTILITY COMMISSION OF TEXAS ADRIANA GONZALES