25.62. Transmission and Distribution System Resiliency Plans.

(a) **Purpose and applicability.** This section allows an electric utility that owns and operates a transmission or distribution system to file a resiliency plan to enhance the resiliency of the electric utility's transmission and distribution system. The requirements of this section will be construed, to the extent practicable, to reflect the following:

(1) Each transmission and distribution system has different system characteristics and faces different resiliency events and resiliency-related risks. The ability to precisely define, measure, and address these events and risks varies. Terms such as "event," "risk," "criteria," and "metric" will be construed pragmatically to provide each utility with the flexibility to develop a well-tailored and systematic approach to improving the resiliency of its system.

(2) A utility seeking approval of a resiliency plan bears the burden of proof on each aspect of its resiliency plan. Nothing in this section categorically limits the type of evidence that a utility may use to meet this burden. The weight given to each piece of evidence will be determined by the commission on a case-by-case basis based on the relevant facts and circumstances. Provisions contained in this section addressing the weight of certain types of evidence are advisory only.

(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 or properly functionalized as distribution plant and, once they are placed into service, are properly recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 352, 353, 360 through 374, 391, and 397. Distribution invested capital includes only costs: for plant that has been placed into service or will be placed into service prior to rates going into effect; that comply with PURA, including §36.053 and §36.058; and that are prudent, reasonable, and necessary. Distribution invested capital does not include: generation-related costs; transmission-related costs, including costs recovered through rates set pursuant to §25.192 of this title (relating to Transmission Service Rates), §25.193 of this title (relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)), or §25.239 of this title (relating to Transmission Cost Recovery Factor for Certain Electric Utilities); indirect corporate costs; capitalized operations and maintenance expenses; and distribution invested capital recovered through a separate rate, including a surcharge, tracker, rider, or other mechanism.

(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** -- an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that 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 distribution invested capital that is:

(A) 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;

(B) reduced by the amount of net plant investment associated with any distribution invested capital included in a utility's rates that is retired or replaced, at the time the associated rates become effective under this section, by resiliency-related distribution invested capital; and

(C) further adjusted to remove accumulated depreciation and accumulated deferred federal income taxes associated with distribution invested capital included in a utility's rates that is retired or replaced, at the time the associated rates become effective under this section, by resiliency-related distribution invested capital.

(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 prevent, withstand, mitigate, or more promptly recover from 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 prevent, withstand, mitigate, or more promptly recover from 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 any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure.

(A) The resiliency plan must identify, for each measure, one or more risks posed by resiliency events that the measure is intended to prevent, withstand, mitigate, or more promptly recover from.

(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, withstanding, mitigating, or more promptly recovering from the risks posed by 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 expected benefits of the resiliency measures including, as applicable, 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 must identify if a resiliency measure is a coordinated effort with federal, state, or local government programs or may benefit from any federal, state, or local government 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.

(vi) The resiliency plan must identify any measures that may require a transmission system outage to implement. The electric utility must coordinate with its independent system operator before implementing these measures. Upon request, the electric utility must provide its independent system operator, using mutually-agreed to transfer and data security procedures, a complete copy of its resiliency plan.

(B) **Resiliency events.**

(i) A resiliency plan must define identify and describe each type of resiliency event and any associated resiliency-related risks the plan is designed to prevent, withstand, mitigate, or more promptly recover from. 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 prevent, withstand, mitigate, or more promptly recover from them.

(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.

(iv) A resiliency plan must provide sufficient evidence to support the presence of and risk posed by each identified resiliency event. The resiliency plan must provide historical evidence of 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. 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 preventing, withstanding, mitigating, or more promptly recovering from the risks associated with the resiliency event it is designed to address.

(i) The resiliency plan must explain the appropriateness 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 or analysis 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, 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), or programs or measures otherwise required by law, the electric utility must distinguish the measures in the resiliency plan from these programs and 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, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments. 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) A utility may deviate from the implementation schedule specified in an approved plan if its independent system operator has not approved an outage that would be required to timely implement the plan.

(G) The resiliency plan must include an executive summary or comprehensive chart that explains the plan objectives, the resiliency events or related risks the plan is designed to address, the plan's proposed resiliency measures, the proposed metrics or criteria for evaluating the plans' effectiveness, the plan's 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.** By the day after it files its application, 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 intervention deadline is 30 days from the date service of notice is complete. The notice must be provided using a reasonable method of notice, to:

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

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

(C) if the resiliency plan is filed by an electric utility operating in an area in Texas that is open to competition and includes a request for a resiliency cost recovery rider, each retail electric provider that is authorized by the registration agent to provide service in the electric utility's service area;

(D) the Office of Public Utility Counsel. Notice delivered to the Office of Public Utility Counsel must include a copy of the resiliency plan, excluding critical energy infrastructure information; and

(E) the independent system operator. Notice delivered to the utility's independent system operator must include a copy of the resiliency plan, excluding critical energy infrastructure information.

(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) Commission staff must review each resiliency plan for sufficiency and file a recommendation on sufficiency within 28 calendar days after the resiliency plan is filed. If commission staff recommends the resiliency plan be found deficient, commission staff must identify the deficiencies in its recommendation. The electric utility will have seven calendar days to file a response.

(B) If the presiding officer concludes the resiliency plan is deficient, the presiding officer will file a notice of deficiency and cite the particular requirements with which the resiliency plan does not comply. The presiding officer must provide the electric utility an opportunity to amend its resiliency plan. Commission staff must file a recommendation on sufficiency within 10 calendar days after the filing of an amended resiliency plan, when the amendment is filed in response to an order concluding that material deficiencies exist in the resiliency plan.

(C) If the presiding officer has not filed a written order concluding that material deficiencies exist in the resiliency plan within 14 working days after a deadline for a recommendation on sufficiency, 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 once 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.

(4) **Commission review of resiliency plan.** In determining whether to approve, deny, or modify a plan, the commission will consider:

(A) the extent to which the plan is expected to enhance system resiliency, including whether the plan prioritizes areas of lower performance;

(B) the estimated costs of implementing the measures proposed in the plan; and

(C) whether the plan is in the public interest. The commission will not approve a plan that is not in the public interest. In evaluating the public interest, the commission may consider:

(i) the extent to which the plan is expected to enhance system resiliency, including:

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

(II) 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, or improve overall service reliability for customers during and following a resiliency event;

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

(IV) 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);

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

(iii) whether there are more efficient, cost-effective, or otherwise superior means of preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the resiliency events addressed by the resiliency plan; or

(iv) other factors deemed relevant by the commission.

(5) 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.

(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 measures in the plan. The commission may 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, or 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. If a utility that files a resiliency plan with the commission does not apply for a rider or rates to recover resiliency plan costs under paragraph (1) of this subsection, after commission review and approval of the resiliency plan, the utility may defer all or a portion of the distribution-related costs relating to the implementation of the resiliency plan for recovery as a regulatory asset under paragraph (2) of this subsection, or in a base-rate proceeding. The regulatory asset may include associated depreciation expense and carrying costs at the utility's weighted average cost of capital established in the commission's final order in the utility's most recent base-rate proceeding in a manner consistent with PURA Chapter 36.

(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 Public Utility Regulatory Act (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) An electric utility may request an RCRR established under this section take effect at any time, except that before an RCRR established under this section may take effect:

(I) all distribution investment included in the RCRR must be providing service to the electric utility's customers, and

(II) the commission must approve RCRR rates in accordance with clause (iv) of this subparagraph.

(iv) An electric utility must submit a separate application requesting RCRR rates.

(I) The utility must provide notice of its application, using a reasonable method of notice, to the parties listed in subsection (d)(1) of this section.

(II) The RCRR rate request must include: the final amount of resiliency-related distribution invested capital closed to plant and in service to be included in the RCRR rates, values necessary to calculate RCRR rates, attachments demonstrating the calculation of RCRR rates consistent with this section, and workpapers supporting the application.

(III) The commission will enter a final order on the application for RCRR rates under this section not later than the 60th day after the date the complete updated request is filed. The commission may extend the deadline for not more than 30 days for good cause.

(v) An electric utility must provide notice, using a reasonable method of notice, of the approved rates and effective date of the approved rates to retail electric providers that are authorized by the registration agent to provide service in the electric utility's distribution service area not later than the 45th day before the date the rates take effect.

(vi) 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 remaining unrecovered 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 §25.243 of this title.

(VI) $\%GROWTH_{CLASS}$ = The greater of $((BD_{C\text{-}CLASS} – BD_{RC\text{-}CLASS}) / BD_{RC\text{-}CLASS})$ or zero.

(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 most recently completed 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 revenue-related tax expense associated with the resiliency-related net distribution invested capital as well as appropriate associated ad valorem tax expense.

(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 most recently completed 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 most recently completed 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 most recently completed 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 most recently completed base-rate proceeding, or zero if there are no distribution cost recovery factor proceedings since the utility's most recently completed 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 most recently completed 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) **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 §25.243 of this title (relating to Distribution Cost Recovery Factor (DCRF)), consistent with PURA §38.078(k).

(A) Notwithstanding the existing requirements of §25.243 of this title, a utility eligible to request a distribution cost recovery factor under §25.243 of this title must, as part of an application under §25.243 of this title, request to include any resiliency-related costs deferred as a regulatory asset under this subsection 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.

(3) **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. In any proceeding in which the commission determines that a utility has included in rates any amounts deemed unreasonable, unnecessary, or imprudent, the commission may order a compliance proceeding to determine the amounts and manner of any necessary refunds to ratepayers, including 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.

(D) In any base-rate proceeding in which resiliency-related costs are being reconciled, the electric utility must separately include as part of its base-rate application testimony, schedules and workpapers sufficient to enable a comprehensive review of all resiliency-related costs included in each and every rider under this subsection that have not yet been reconciled. Such information must include, but is not limited to, the dates when the individual resiliency-related projects began providing service to the public, as well as the costs associated with the individual resiliency-related projects.

(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, beginning the year after the plan is approved. 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 a resiliency plan previously-implemented by the electric utility;

(B) an evaluation of the effectiveness of each implemented resiliency plan measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by 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, as appropriate for each measure, 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.

(3) When submitting an updated resiliency plan, the utility must include in the evidence supporting the plan, any information from prior resiliency benefit updates related to previously-approved measures designed to address the same or similar resiliency risks.

(4) An electric utility is required to maintain records associated with the information referred to in this subsection for five years, beginning the year after the plan is approved. Upon request by commission staff an electric utility must provide any additional information and updates on the status of the resiliency plan submitted.