PROJECT NO. 55250

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

ORDER ADOPTING NEW 16 TAC §25.62

The Public Utility Commission of Texas (commission) adopts new 16 Texas Administrative Code (TAC) §25.62, relating to Transmission and Distribution Resiliency Plans. The commission adopts the rule with changes to the proposed text as published in the September 29, 2023 issue of the *Texas Register* (48 TexReg 5600). 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. Additionally, the rule delineates the commission review process for the plans.

The commission received comments on the proposed rule from AEP Texas Inc. (AEP), the Alliance for Retail Marketers (ARM), CenterPoint Energy Houston Electric, LLC (CenterPoint), the City of Houston (Houston), Don K Brown, the Electric Reliability Council of Texas, Inc. (ERCOT), Electric Transmission Texas, LLC (ETT), Entergy Texas Inc. (ETI), Grid Assurance, LLC (Grid Assurance), Hunt Energy Network, LLC (HEN), Microgrid Resource Coalition (MRC), Office of Public Utility Council (OPUC), Oncor Electric Delivery Company, LLC (Oncor), RPower LLC (RPower), Secure the Grid Coalition (SGC), South Central Partnership for Energy Efficiency as a Resource (SPEER), Southwestern Electric Power Company (SWEPCO), Southwestern Public Service Company (SPS), the Steering Committee of Cities served by Oncor and Texas Coalition for Affordable Power (OCSC & TCAP), Texas Advanced Energy Business Alliance (TAEBA), Texas Consumer Association and Alison Silverstein Consulting (TCA & ASC), Texas Electric Cooperatives Inc. (TEC), Texas Energy Association for Marketers (TEAM), Texas Industrial Energy Consumers (TIEC), and Texas New Mexico Power Company (TNMP).

Oncor requested a hearing on October 6, 2023 and withdrew the request on October 12, 2023. No other parties requested a hearing for this rulemaking.

General Comments

Don K. Brown filed comments in support of the rule but did not recommend any specific modifications to the text of the rule as proposed.

Proposed §25.62(a) - Applicability

Subsection (a) describes the applicability of the rule.

ETT recommended clarifying that the rule applies to both electric utilities that own and operate transmission and distribution systems, as well as transmission only entities such as itself.

SPS recommended clarifying in the proposed rule that a utility may, but is not required to, file a resiliency plan.

Commission Response

The commission agrees with ETT's comments and modifies the rule language to clarify that the rule applies to entities that own and operate transmission and distribution systems as well as entities that own transmission only systems. The commission declines to modify the rule to clarify that a utility is not required to submit a resiliency plan, because it is unnecessary. There are no provisions in the rule that require a utility to file a resiliency plan. The use of the term 'may' in proposed subsection (c) indicates the submission of a resiliency plan is permissive.

Purpose Language

The commission further modifies proposed subsection (a) to include additional purpose language. This language provides additional clarity on the intended interpretation of several provisions of the rule. Specifically, it emphasizes that certain rule provisions are not intended to limit the flexibility with which a utility can appropriately tailor its resiliency plan to its system. This will be discussed in further detail below.

Proposed §25.62(b) – Definitions

Proposed subsection (b) defines certain terms used in the rule.

TNMP recommended to either add definitions for the terms "resiliency," "resiliency measures," and "resiliency methods" or clarify that each utility can define resiliency and the related terms based on its service territory. TCA & ASC and SGC also recommended adding a definition of "resiliency." SGC provided specific language to add to the definition of 'resiliency'.

Oncor recommended defining the term “resiliency-related regulatory asset” to specify the categories of costs eligible for recovery through the deferred regulatory asset.

TAEBA and SPEER recommended that a definition for “Distributed Energy Resource (DER) Integration Measures” and “Distributed Energy Resource” be included.

Commission Response

The commission declines to add definitions of the terms resiliency, resiliency measures, resiliency methods, or resiliency-related regulatory asset at this time. However, modifications are made throughout the rule to clarify the intended meaning of these terms in context. The commission also declines to add distributed energy resources (DER)-related definitions, because the commission did not accept related recommendations to modify the substantive provisions of the rule to use these words.

Proposed §25.62(b)(1) – Definition of ‘Distributed Invested Capital’

Subsection (b)(1) defines the term “Distributed invested capital” and provides details about the types of costs that are and are not allowed to be categorized as distributed invested capital.

Houston recommended the commission remove references to Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 352 and 353 because these accounts are for transmission structures and transmission station equipment and must be recovered in the utility’s transmission cost of service (TCOS) rates.

AEP, CenterPoint, ETI, Oncor, and TNMP recommended the definition include FERC Uniform System of Accounts 303 (Miscellaneous Intangible Plant), 391 (Office Furniture and Equipment), and 397 (Communication Equipment) to align it with the existing definition of the term in 16 TAC §25.243, relating to Distribution Cost Recovery Factor (DCRF). AEP, TNMP and Oncor recommended the commission also include language related to defining distribution invested capital as invested capital that is categorized *or functionalized* as distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks, as added by SB1015 (enacted by the 88th Texas Legislature).

Commission Response

The commission disagrees with Houston regarding removing references to FERC accounts 352 and 353 in the definition of the term distributed invested capital. A portion of the costs in those accounts may primarily serve and be properly functionalized to the distribution function and, therefore, not qualify for inclusion in transmission service rates under 16 TAC §25.192. The commission agrees with the other commenters, modifies the proposed definition to align it to the definition in 16 TAC §25.243, and adds statutory language to reflect the changes in the definition as described in Senate Bill 1015 (88th Legislature, R.S.).

Proposed §25.62(b)(3) – Definition of Resiliency Event

Subsection (b)(3) defines the term "resiliency event" as a low frequency, high impact event that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems.

ETI, ETT, SWEPCO, Oncor, and TNMP recommended the commission remove the phrase "low frequency" from the definition. ETI, Oncor, and TNMP further recommended the removal of the phrase "high impact," and ETI and Oncor recommended additional modifications to the proposed definition. Oncor recommended replacing the term "resiliency event" with "resiliency risk" and proposed listing the major categories of resiliency risks as part of the definition. SPS proposed adding language to the definition to clarify that specific utility system and service territory conditions may inform a utility's consideration of "low frequency" as well as "high impact." SPEER recommended redefining resiliency events to include historical data on prolonged heat and cold events.

SWEPCO recommended replacing the word 'mitigated' in the definitions with more descriptive words and CenterPoint recommended striking the word "mitigated" from the definition.

Commission Response

The commission modifies the rule to include the major categories of resiliency events as recommended by Oncor but declines to replace the term with "resiliency risk." The commission instead includes purpose language in subsection (a)(1) that requires a pragmatic construal of the term resiliency event. Some resiliency events, such as hurricanes, may pose multiple types of resiliency risks. In other instances, such as with a lightning strike, the occurrence might be characterized as an event, or a risk associated with a larger event. The diverse nature of resiliency threats that a system can face requires that each utility be given the flexibility to characterize and analyze these threats in a way that makes sense for its system. This emphasis on flexibility should address Oncor's concerns.

The commission agrees that system resiliency may not always be limited to the ability to withstand only low frequency, high impact events and removes these phrases from the proposed definition. Further, the intended contribution of these phrases is captured by the portion of the definition that reads: "[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." In essence, the focus should be on resiliency, and not reliability.

The commission also agrees with the commenters and replaces the term mitigate with more descriptive terminology throughout the rule, as appropriate, despite having removed the term from this definition. The commission declines to amend the definition of "resiliency event" to include historical data on prolonged heat and cold events. Subsection (c)(2)(B) establishes sufficiently broad requirements for detailed descriptions of a resiliency event.

Proposed §25.62(b)(4) Resiliency-related Distribution Invested Capital and (b)(5) Resiliency-related Net Distribution Invested Capital.

Subsection (b)(4) defines the term "resiliency-related distribution invested capital" as distributed invested capital associated with the resiliency plan that is not included in a utility's rates. Subsection (b)(5) defines the term "resiliency-related net distribution invested capital" as resiliency-related invested capital that is adjusted for depreciation and changes in taxes.

TIEC recommended the addition of clarifying language to the definition of "resiliency-related distribution invested capital" that would limit a utility to recovery of the incremental cost of resiliency measures to prevent double recovery of invested capital through a resiliency plan. TIEC contended that utilities should be allowed to recover only the incremental costs of resiliency measures that are not already being recovered through existing delivery rates. TIEC explained that resiliency plans may involve replacing or retiring existing infrastructure that was included in setting base rates. If the costs associated with the retired or replaced facilities are not removed from base rates, the utilities will continue recovering on the retired facilities until their next full rate review.

TIEC also recommended that the commission add language to the proposed definition of "resiliency-related net distribution invested capital" 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, to prevent double recovery of invested capital through a resiliency plan.

Commission Response

The commission modifies the definition of "resiliency-related net distribution invested capital" to require an offset equal to the amount of net plant investment included in a utility's rates that is retired or replaced by resiliency-related distribution invested capital. The commission also modifies the definition to remove accumulated depreciation and accumulated deferred federal income taxes associated with distribution invested capital that is retired or replaced by resiliency-related distribution invested capital. This will allow a utility to continue to recover the costs associated with any retired assets replaced by resiliency-related distribution investments, but will not provide a return on those retired investments. This approach strikes the right balance by encouraging utilities to invest in resiliency without fear of losing recovery of assets previously deemed prudent by the commission, and protecting ratepayers from providing utilities a return on investments that are no longer used and useful and, therefore, the ratepayers are no longer benefitting from. This is also consistent with precedent allowing a return of, but not on, rate base amounts associated with assets that are no longer used and useful in providing service.

Proposed §25.62(c)(1) – Resiliency measures and methods

Subsection (c)(1) specifies that a resiliency plan can consist of one or more resiliency measures designed to mitigate the risks posed by a resiliency event and lists the methods that an electric utility can utilize as a resiliency measure in its resiliency plan.

SWEPCO recommended removing the term "mitigate" and provided other modifications to subsection (c)(1), explaining that an event cannot be mitigated but only the impact of the event can be mitigated, and the purpose of a resiliency measure is to "prepare for, adapt to, respond to, or recover from" a disruptive event or risk. SWEPCO and TNMP recommended making the same clarification for subsection (c)(2)(A).

Commission Response

The commission agrees the term "mitigate" is imprecise and does not fully capture the breadth of possible resiliency measures. The commission modifies the rule to indicate that the measures must be designed to prevent, withstand, mitigate, or more promptly recover from the risks associated with a resiliency event. The commission applies this change uniformly throughout the rule.

Both TAEBA and HEN recommended adding additional methods to the list to enable greater utilization of DER resources for resiliency purposes. Specifically, HEN recommended adding the segmentation of distribution facilities for improved load shed management and expediting the interconnection of DER resources to the list of methods that resiliency measures may utilize.

SPS recommended adding a new method, “promoting public safety,” to the list of methods. TCA & ASC recommend consideration of third party and private non-wires measures and non-utility-initiated investments to be included as resiliency methods.

Grid Assurance recommended modifying the rule to include the phrases “at least” and “including but not limited to” in subsection (c)(1) to reflect statutory intent and clarify that the methods included in the plan are not limited to the ten methods listed in both the statute and the proposed rule. ETI and AEP agreed with Grid Assurance’s interpretation. All three commenters provided language to clarify their interpretation of statutory intent. Grid Assurance also advocated for utilities to have the flexibility to engage in activities and methods for system resiliency that are not part of the ten methods listed, such as electric utilities’ access to resources for replacements of key equipment.

Commission Response

The commission declines to modify the rule to add resiliency methods beyond those that are included in the statute. The commission interprets the statutory language “through at least one of the following methods” as permitting the use of one or more of the listed methods. If

the list were intended to be nonexclusive, it would have contained a term of expansion such as "including." This rule provides access to novel cost recovery mechanisms, and it is beyond the scope of this rulemaking to consider whether additional methods other than those listed in statute should be included.

ERCOT recommended that an electric utility be required to coordinate with ERCOT concerning any transmission facility outages that may result from an electric utility installing transmission upgrades as part of its resiliency plan. ERCOT also argued transmission upgrades that are part of a resiliency plan and that require a change in the modeled characteristics of any transmission facility in the ERCOT region should also be coordinated. ERCOT further recommended that an electric utility not be required to comply with the implementation schedule of an approved resiliency plan if ERCOT has not approved an outage that would be required to timely implement the plan.

Commission Response

The commission agrees with ERCOT's recommendations. Subsection (c)(2)(A)(vi) is added to require a utility to include, in its resiliency plan, details about coordination with the utility's independent system operator (ISO) for any transmission system outages that may be required to implement an approved resiliency plan. Subsection (c)(2)(F) is added to allow a utility to revise the implementation schedule specified in an approved resiliency plan if the utility's ISO has not approved an outage that would be required to timely implement the plan. Lastly, subsection (d)(1)(D) is added to include the utility's ISO as an entity that must

be notified and that receives a copy of a resiliency plan when it is submitted by an electric utility.

Proposed §25.62(c)(2) – Contents of the resiliency plan

Subsection (c)(2) outlines the supporting documentation required in a resiliency plan.

SWEPCO recommended that subsection (c)(2) use "or" instead of "and" to clarify that not all listed items are applicable to all resiliency plan measures. Similarly, TNMP stated that the listed items are broad and ambiguous and suggested either striking the list or adding the phrase "to the extent applicable" to the end of the list.

Commission Response

The commission agrees with SWEPCO and modifies the rule language to replace "and" with "or" to clarify that all items listed do not necessarily need to be part of all resiliency measures that are part of a resiliency plan. This modification should also address TNMP's concerns.

Proposed §25.62(c)(2)(A)

Subsection (c)(2)(A) lists the information that must be included for each measure of a resiliency plan.

TEAM recommended adding a clause to subsection (c)(2)(A) that would require a utility filing a resiliency plan to identify the expected method of cost recovery for each resiliency measure but would not make the expected method of cost recovery binding. TEAM explained that the anticipated cost recovery mechanism would provide insight into when the rate changes associated with a resiliency plan would take effect. TEAM provided redlines consistent with its recommendation.

Commission Response

The commission declines to require the inclusion of nonbinding expectations for which cost recovery mechanism will be used for each resiliency measure. Nonbinding suggestions should not be relied upon, and the commission has implemented other requested modifications that will provide REPs with more foresight into the timing of rate changes, as discussed elsewhere in this order.

HEN recommended adding a clause to subsection (c)(2)(A) that would require a utility's resiliency plan to include an analysis of the potential integration of DER and microgrid solutions and develop "non-discriminatory metrics" to allow market participants to determine system adequacy for the interconnection of demand-side energy resilience solutions.

Commission Response

The commission declines to require every resiliency plan to include an analysis of potential integration of DER and microgrid solutions because such a mandatory requirement is beyond the noticed scope of this rulemaking.

Proposed §25.62(c)(2)(A)(i) - Prioritization of resiliency events

Subsection (c)(2)(A)(i) requires an electric utility to explain the prioritization of the identified resiliency events and, if applicable, the particular geographic area, system, or facilities where the measure will be implemented.

TNMP requested clarification of the term "prioritization," noting that the term is used in HB 2555 only in relation to areas of lower performance. TNMP alternatively requested deletion of this clause.

Commission Response

A transmission or distribution system may face a multitude of potential resiliency events across its service territory. It is unlikely that a resiliency plan will contain measures to address all of these risks. Further, a resiliency plan may implement these measures in specific geographic locations or in a particular order. Subsection (c)(2)(A)(i) requires a utility to provide an explanation for why it prioritized the selection of each event for inclusion in the plan and any context necessary to assist the commission in evaluating the plan's systematic approach. It does not require, for instance, a rank-ordering of where each proposed measure falls in the utility's priorities. If, however, a utility utilized tiers of risks or another organizational framework in designing its plan, it should provide an explanation of where each measure falls in that framework. The commission declines to accept TNMP's suggestion to delete the clause for the reasons explained above.

Proposed §25.62(c)(2)(A)(ii) Evidence of effectiveness of a resiliency measure

Subsection (c)(2)(A)(ii) requires an electric utility to provide evidence of effectiveness of the resiliency measures included in its resiliency plan. This clause also specifies that greater weight is given to evidence that is quantitative, performance based or provided by an independent entity.

Houston recommended modifying the rule to require an electric utility to include quantitative or performance-based evidence for the activities within the plan. Houston explained that this evidence is necessary to justify the activities and to set measurable benefits up front so evaluation of these activities at the third anniversary of the plan is possible.

SPS advocated for creating flexibility for electric utilities to submit evidence of effectiveness. SPS stated that although it is reasonable to ask the utility to provide quantitative, performance-based evidence to support its resiliency strategy, it is more difficult to provide such evidence for a new resiliency investment. TNMP also advocated for removing the clause for similar reasons as SPS.

AEP commented that the proposed language was overly prescriptive because types of evidence available for each measure may vary depending on the unique set of circumstances presented by each case.

Commission Response

The commission agrees that different types of evidence will be available to support the effectiveness of different types of resiliency measures. The commission modifies the rule to include a new paragraph is subsection (a) that clarifies that a utility bears the burden of

proof on all aspects of its plan, that the utility is not restricted in the types of evidence that it can provide to support its plan, and that the commission will evaluate this evidence on a case-by-case basis. However, the commission declines to remove the rule text that supports the use of quantitative and performance-based evidence because this provides useful guidance that this type of evidence should be provided, when available. When such information is not available, other evidence such as qualitative evidence, predictive models, or attribute-based evidence may be provided.

AEP and ETI recommended removing language related to an independent entity providing evidence of effectiveness of resiliency measures, stating that the commission is capable of appropriately weighing evidence based on facts and circumstances.

Oncor commented that the proposed language related to an independent entity is ambiguous and recommended revisions so that it refers to "an entity or consultant that is not employed by (but may be retained as a consultant by) the utility and that has relevant expertise."

Commission Response

The commission declines to remove this provision. The language is advisory and intended to provide guidance to a utility in preparing its plan.

The commission further declines to modify the rule as requested by Oncor because Oncor's suggestion is too narrow. The commission agrees that paid consultants may still be considered independent entities, but evidence "provided by an independent entity" may also

refer to studies conducted by national labs, case studies conducted in other service territories, or other similar sources. The intent of this language is merely to highlight the value that independent evaluation or expertise can provide. In many instances, a utility will be able to support the effectiveness of a measure without relying upon independent entities.

Proposed §25.62(c)(2)(A)(iii) – Explanation of benefits of resiliency measures

Subsection (c)(2)(A)(iii) requires an electric utility to explain the benefits of a proposed resiliency measure, including system restoration costs, frequency and duration of outages, and overall service reliability for customers, including critical load customers.

AEP stated that the benefit of a resiliency measure may not be limited to system restoration cost and frequency and duration of outages. AEP explained that reduced exposure to resiliency events is also a benefit and provided related rule language.

Commission Response

The commission declines to modify the proposed rule because modification is unnecessary. Under the Texas Code Construction Act, "including" is a term of expansion. Accordingly, the list of potential benefits is nonexclusive, and a utility may include information on other benefits a proposed resiliency measure will provide.

Proposed §25.62(c)(2)(A)(v) – Selection of resiliency measure over alternatives

Subsection (c)(2)(A)(v) requires a resiliency plan to explain the selection of a resiliency measure over any reasonable and readily identifiable alternatives.

SWEPCO, AEP, ETI, and TNMP suggested deleting subsection (c)(2)(A)(v). ETI, AEP and CenterPoint explained that, given that utilities bear the burden of proof in these proceedings, they have an incentive to include such information, when available. CenterPoint added that such a requirement is unnecessary because the commission conducts a prudence analysis after the electric utility has incurred costs. TNMP commented that the proposed language is unclear and ambiguous, explaining that although some measures may have no alternatives, other measures may have innumerable “reasonable and readily-identifiable alternatives.”

Oncor commented that the requirement to provide alternatives will lead to unnecessary controversy during the evaluation of resiliency plans given the impossibility of assessing the complete universe of potential alternatives for certain measures, and the fact that there may not be any reasonable, readily identifiable alternatives for other measures. Oncor proposes that the requirement be an explanation of the selection of each measure over reasonable and readily identifiable alternatives, but only in those cases where there are any such reasonable and apparent alternatives.

Commission Response

The commission declines to modify the rule as requested by the commenters. To determine the appropriateness of a resiliency measure, the commission requires information related to alternatives. Including, as part of the filed plan, justification for why available alternative measures were not chosen will facilitate the commission’s review within the 180 days provided by statute.

The commission does not share commenters' concerns regarding the terms "any" and "reasonable and readily-identifiable". The language itself provides that, in many instances, there may not be any alternatives to evaluate. Further, the rule does not require an assessment of the complete universe of potential alternatives. As CenterPoint notes, the utility does have the burden of proof, which may even require the utility to support its measures over alternatives that are not reasonable or readily-identifiable. However, the intent of this requirement is to introduce evidence of known alternatives at the outset of the proceeding. To mitigate prolonged controversy over whether a particular alternative is "reasonable and readily-identifiable," the commission modifies the rule to allow a sufficiency recommendation from commission staff only.

MRC, RPower and HEN recommended adding rule language that requires the utilities to consider customer-owned or third party-owned microgrids or distributed energy resources to increase distribution system resiliency, reduce frequency or duration of outages, or lower costs to customers. HEN recommended an addition to clause (v) that would require utilities to analyze and explain the selection of each resiliency measure over alternatives that could be provided by "non-regulated, competitive entities." MRC recommended that modernizing of electric utilities' facilities, including digitization of distribution circuits, be included in every approved resiliency plan.

Commission Response

The commission declines to explicitly require a resiliency plan to evaluate any customer-owned generation resources as alternatives to the measures proposed in a resiliency plan.

Neither electric utilities nor the commission have the authority to require customers to utilize any form of generation to improve system resiliency. Accordingly, these are not alternatives that a utility is capable of implementing. However, if existing distributed generation resources or potential future distributed generation resources might reduce the risks posed by resiliency events, the commission may take this into account when evaluating the necessity of the proposed measure. Further, if a potential resiliency measure could be expected to result in a change in demand-side behavior, this may also be considered, as appropriate.

Proposed §25.62(c)(2)(B)(i) and §25.62(c)(2)(B)(ii) – Defining resiliency events

Subsection (c)(2)(B)(i) requires an electric utility to define a resiliency event, the impact of which the resiliency plan is designed to mitigate. Subsection (c)(2)(B)(ii) allows the utility to include magnitude thresholds for a resiliency event in the definition to conduct a granular analysis of the risk.

TNMP recommended altering the language of subsection (c)(2)(B)(i) to note that the risks from resiliency events are what is mitigated, rather than the resiliency events themselves.

Commission Response

The commission modifies the rule to also require the utility to define any associated resiliency risks the plan is designed to address. Further, under subsection (a)(2), terms such as "event" and "risk" are to be construed pragmatically to alleviate concerns over whether something precisely qualifies as an event, a risk, or an impact of a risk. The essence of the requirement

is that the utility defines the problem that is being addressed in a manner that will allow the commission to evaluate and track the effectiveness of the solution.

AEP recommended identifying the resiliency event instead of defining it because the term "define" suggests a level of precision that is not possible or desirable. SWEPCO recommended deleting language that requires resiliency events to be defined with sufficient detail.

Commission Response

The commission declines to modify the rule to replace the term "define" with "identify." The resiliency events and risks faced by each utility are different, so this rule is structured to provide a utility with flexibility in identifying and characterizing these issues. In light of this flexibility, it will be impossible for the commission to evaluate these events and risks if what constitutes each type of event is not defined as precisely as possible. These definitions need not resemble a legal or dictionary definition. Rather, they must identify the key parameters that establish whether an event has occurred or not (e.g., how deep does running water have to be to present flood-related risks). Further, subsection (a)(1) acknowledges that the precision with which these events can be defined will vary, and the commission will take a pragmatic approach to evaluating whether enough detail has been provided.

Proposed §25.62(c)(2)(B)(iv) – Evidence to support presence of risk

Subsection (c)(2)(B)(iv) requires an electric utility to provide evidence to support the presence of a risk posed by an identified resiliency event. The rule clause also clarifies that the commission will give weight to studies conducted by an ISO or an independent entity with relevant experience.

TAEBA recommended that utilities be allowed to submit historical evidence and results from predictive models as evidence of the presence of risk. Oncor, AEP, and ETI recommended deleting the clause because it was duplicative of subsection (c)(2)(A)(ii), and it is too prescriptive. AEP asserted that commissioners are in the best position to weigh the evidence. TCA & ASC recommended requiring a utility to use credible forward-looking threat analyses and sources in addition to historical data.

SPS suggested striking language referring to historical data related to resiliency events and reducing the weight given to studies conducted by independent entities. SWEPCO stated that evidence from an ISO or independent entity should not be required because a utility can provide evidence to support presence of risk without additional information from a third party.

Commission Response

The commission declines to modify the rule to either explicitly *allow* or explicitly *require* a utility to provide a particular type of evidence in support of its plan. The utility has the burden of proof and may rely upon the evidence of its choice in attempting to satisfy that burden. The commission also declines to strike the language giving great weight to studies conducted by independent entities or ISOs, because this language is advisory and intended to provide guidance to a utility in preparing its plan.

Proposed §25.62(c)(2)(C) – Evaluation Metric or Criteria

Subsection (c)(2)(C) requires a metric or criteria for evaluating the effectiveness of each resiliency measure proposed in the resiliency plan.

SWEPCO and AEP recommended deleting subsection (c)(2)(C). SWEPCO clarified that quantification of a resiliency measure's effectiveness (such as restoration cost dollars saved, or customer outage minutes avoided) in such circumstances would be speculative. SWEPCO conjectured that speculative estimates of effectiveness might trigger intervenors recommending disallowance of costs based on conclusions drawn from such information. Further, SWEPCO asserted, this could also prompt the commission to bring an enforcement action against a utility for its resiliency measures' performance during an event. SWEPCO stated that such uncertainty may cause hesitance among utilities to propose a resiliency plan, due to the inherent risk that doing so would create.

AEP recommended deleting the word "metric" throughout the rule because the concept of a metric suggests that the effectiveness of a resiliency measure depends on how a utility recovers from a resiliency event. AEP explained that resiliency is largely about what does not happen, which is inherently difficult to measure.

Commission Response

The commission declines to delete the word "metric" or remove this requirement from the rule. However, the commission does modify the rule to include language in subsection (a)(1) indicating that the terms "metric" and "criteria" are to be construed pragmatically.

Further, the commission agrees that some intended resiliency benefits will be difficult to measure. This requirement is designed to give utilities the ability to articulate the benefits of a resiliency measure in a manner suited to that measure. If a particular measure cannot be evaluated quantitatively, the utility must explain why. A lack of quantifiability does not necessarily disqualify a measure from approval.

TNMP recommended removing subsection (c)(2)(C)(iii) because of lack of clarity on how to estimate “expected effectiveness” of various measures. TNMP also argues this would limit the application of new technologies, because “there would be no ability to estimate their ‘expected effectiveness.’”

Commission Response

The commission disagrees that this provision lacks clarity on how effectiveness is supposed to be estimated. The effectiveness will be determined according to the criteria or metric proposed by the utility. This gives the utility flexibility to align the assessment of effectiveness with the utility’s objective in proposing the resiliency measure.

The commission also disagrees that this requirement limits the use of new technologies or methods. The utility is merely required to provide its best assessment of what improvements it expects if the proposed measure is implemented. Whether the commission finds that assessment compelling enough to consider the measure will vary on a case-by-case basis.

If a new technology or strategy is so untested that the utility is completely unable to make any sort of assessment, projection, or explanation of the benefits it will provide, the commission will take that into account when analyzing the measure. This requirement is essential for providing the commission with insight into why a utility is proposing the measure and how speculative the benefits are.

ETI and Oncor recommended modifications to the proposed rule that would allow the utilities the flexibility to choose an evaluation metric. ETI recommended that utilities be permitted to apply an evaluation metric to their plan as a whole, to certain groups of measures, and individual measures, as appropriate. Oncor recommended concluding the subparagraph with “if applicable” to make the requirement conditional.

CenterPoint recommended replacing the subparagraph with a requirement for retrospective evaluation of a resiliency measure. CenterPoint suggested that a utility conduct a post-resiliency event analysis that analyzes the impact of a resiliency measure on service restoration times and costs, wherever possible. Oncor provided language to compare the expected effectiveness of a measure in an updated resiliency plan with actual results achieved by the utility from implementation of the measure.

Commission Response

The commission agrees with ETI that the same evaluation metric may be used to evaluate a group of measures or the entire resiliency plan. The proposed rule allows each utility to propose how each measure should be evaluated, which may include that it should be

evaluated in conjunction with one or more other measures included in the plan. This evaluation strategy is most appropriate when each measure functions as a component of a larger strategy to achieve a single resiliency-related objective.

However, if a utility proposes that a group of measures be evaluated together, the commission may not be able to evaluate the contribution that each measure makes to the effectiveness of that group of measures. This may result in undesirable outcomes, such as the commission rejecting multiple measures when it might have otherwise determined that one or more of the measures merited approval. To avoid this outcome, if appropriate, an electric utility could provide a primary evaluation of a group of measures and a supplemental evaluation of any individual measures that could provide standalone value.

The commission declines to make the modifications suggested by Oncor. The submission of an evaluation metric or criteria cannot be conditional for the reasons discussed above. However, the commission does modify subsection (g) of the rule to require evidence of the effectiveness of prior resiliency measures to be provided as part of any updated resiliency plans that include measures designed to address similar resiliency events.

SPS commented that subsection (c)(2)(C)(i) requires the resiliency plan to include documentation necessary to support the use of the selected evaluation metric but provides no guidelines regarding what will be deemed as sufficient documentation.

Commission Response

The commission agrees and modifies the rule to require only an explanation of the appropriateness of the selected metric or criteria. However, a utility does have the burden of proof regarding the appropriateness of the metric or criteria, so some evidence may need to be provided if the appropriateness is not a simple metric such as restoration time or number of outages. This may be of particular importance in areas such as cybersecurity, which may contain risks and concepts that are less familiar to those without special expertise in that area.

Proposed §25.62(c)(2)(D) – Distinction between the proposed resiliency measure and similar existing programs or measures

Subsection (c)(2)(D) requires an electric utility to distinguish the resiliency measures proposed in the resiliency plan from similar existing programs required by law, such as §25.95 and §25.96. The provision also requires an explanation of how existing measures or programs similar to the proposed resiliency related measures or programs will work in conjunction with one another.

SWEPCO recommended removing the references to §25.95 and §25.96 as examples of other requirements that are required by law, because these are only reporting requirements.

Commission Response

The commission agrees with SWEPCO's comments and clarifies the proposed rule to reflect that these programs are not required by law. However, the commission retains the

references as examples of existing programs that must be distinguished from proposed resiliency measures.

CenterPoint recommended revising the rule to make the requirement to distinguish resiliency measures from existing general resiliency projects permissive.

Commission Response

The commission disagrees with CenterPoint's recommendation and declines to modify the proposed rule. Clear distinction between existing and proposed resiliency activities is necessary for the commission's review of proposed plans. The commission will use the information to evaluate the potential for double recovery of investments, as well as duplicative investments.

OCSC & TCAP recommended requiring the electric utility to provide both existing measures or programs that are similar to resiliency related measures and programs' FERC accounts, investments, equipment, and objectives to distinguish between both resiliency measures and existing programs.

Commission Response

The commission modifies the proposed rule text to clarify that the electric utility is required to distinguish between resiliency measures that are similar to the existing programs and measures currently being undertaken and those that are otherwise required by law. The commission declines to modify the proposed rule to specify which precise information is

required, such as FERC accounts of existing expenses, to distinguish between current and proposes programs.

Houston cautioned that utilities may seek to move standard maintenance programs, storm hardening programs, or cyber and physical security programs mandated by NERC as resiliency measures, into a resiliency plan. Houston recommended that only new programs or specifically expanded programs beyond the utilities' storm hardening measures described in their current filings for §25.95 or vegetation management be included in the Resiliency Cost Recovery Rider.

Commission Response

The commission shares Houston's concerns. The existing rule expressly requires utilities to distinguish its proposed resiliency measures from any existing measures and program, and any measures are programs that are required by law. Further, utilities are only permitted to recovery incremental expenses incurred in implementing resiliency plans.

Proposed §25.62(c)(2)(F) - Contents of the resiliency plan

Subsection (c)(2)(F) requires an executive summary of the resiliency plan.

TCA & ASC commented that "the rule should require the [resiliency] plan to list all proposed resilience measures in a table with associated resilience events and prioritize those measures that constructively address multiple threats."

Commission Response

The commission agrees that such a chart could be beneficial, and modifies adopted subsection (c)(2)(G) to allow the utility to present the information required in the executive summary or in the form of a chart. Additional modifications are made to clarify the commission's intent. The commission declines to require the utility to prioritize measures that address multiple threats. Such a uniform requirement would undermine the utility's ability to prioritize particularly acute resiliency risks or otherwise tailor a reliability plan to the resiliency risks faced by that system.

Proposed §25.62(d)(1) – Notice and intervention deadline

Subsection (d)(1) prescribes the notice and intervention deadlines for an electric utility upon filing a resiliency plan with the commission.

Houston and ERCOT commented that subsection (d)(1) should be revised to require utilities in the ERCOT region to provide ERCOT with notice and a copy of the application for a resiliency plan. ERCOT further recommended language authorizing ERCOT to obtain, upon request, a complete copy of the resiliency plan filing within the same scope of disclosure afforded to OPUC. Houston also recommended subsection (d)(1) be amended to require non-ERCOT utilities to provide the same information to the applicable ISO.

Commission Response

The commission agrees that notice to the appropriate independent system operator is beneficial and adds new §25.62(d)(1)(E). The commission also modifies the rule to require

the utility to provide its independent system operator with a complete copy of its resiliency plan, upon request.

AEP recommended notice by e-mail be permitted under subsection (d)(1) because doing so would be consistent with the commission's order suspending rules in Project Number 50664 in 2020 and has proven to be a cost-effective alternative to notice by mail.

Oncor recommended subsection (d)(1) to be revised to match the notice and intervention deadline provision in §25.243(e)(2). In contrast, OPUC recommended the deadline to intervene be consistent with §22.51(a)(1)(F), which is "45 days after the filing of a complete application," and that an application be considered complete when commission staff makes a sufficiency determination regarding notice and the completeness of the application.

Commission Response

The commission modifies the notice language to match §25.243. Under this modification, the utility may provide notice using "a reasonable method of notice," which in most instances includes email notice, and for some parties, includes a market notice.

The commission also modifies the rule to extend the intervention deadline from 20 days after the filing of the application to 30 days from the date service of notice is complete.

Proposed §25.62(d)(1)(C) – Notice to OPUC

Subsection (d)(1)(C) requires that OPUC be provided notice of the filing of a resiliency plan, which must include a complete copy of the resiliency plan.

AEP recommended §25.62(d)(1)(C) be revised to exclude providing Critical Energy/Electric Infrastructure Information (CEII) automatically through notice to OPUC. AEP provided redlines consistent with its recommendation.

Commission Response

The commission agrees and modifies the rule accordingly.

New §25.62(d)(1)(C) – Notice to REPs of RCRR effective date

TEAM recommended adding a new subparagraph to subsection (d)(1), which would require a utility to provide notice directly to REPs of the filing of a resiliency application as it would serve as an "advanced signal" to REPs in advance of a possible rate change.

Commission Response

The commission agrees and modifies the rule to notify REPs of a new resiliency plan application.

Proposed §25.62(d)(2) – Sufficiency of resiliency plan

Subsection (d)(2) specifies the criteria for sufficiency of a resiliency plan and the timeline, requirements, and procedures for such a review by the commission, which includes allowing parties to file motions of deficiency.

To account for concerns raised by commenters throughout the rule, such as the definition of resiliency event or whether alternative measures are reasonable and readily-identifiable and, thus, need to be evaluated in the plan, the commission streamlines the sufficiency determination process by modifying the rule to remove the ability of parties to file motions of deficiency and replaces it with a commission staff recommendation on sufficiency. Under this process, commission staff will have 28 days from the date a resiliency plan is filed to provide a recommendation on sufficiency, and the utility will have seven days to respond. If the presiding officer determines the plan is deficient, the utility may amend its plan, and staff will have 10 days to provide an updated recommendation. Finally, if the presiding officer has not ruled on sufficiency within 14 days after a deadline for a sufficiency recommendation, the plan is deemed sufficient. This process is consistent with the process utilized in several other commission rules.

ETI recommended the timeline in subsection (d)(2) to respond to a deficiency motion on an initial application be extended from five working days to 10 calendar days. ETI also recommended that the timeline in subsection (d)(2) for an automatic determination of sufficiency be extended from 35 calendar days to 40 calendar days.

Commission Response

As noted in the above discussion, the commission modifies response deadline from five working days to seven calendar days. The commission declines to extend the deadline to ten calendar days because the shift to a commission staff-led sufficiency review process ensures that the utility will have to respond to only one filing on sufficiency. The commission also declines to extend the automatic sufficiency determination to 40 days, because this is no longer applicable to the structure of the rule.

Proposed §25.62(d)(3) – Approval, modification, or denial of a resiliency plan

Subsection (d)(3) specifies the procedure and timeline for commission approval, modification, or denial of a resiliency plan.

Houston stated it would be "more efficient" if the procedural schedule for deadlines in a resiliency plan proceeding were similar to the procedural schedule of a general rate case proceeding. Further, Houston recommended a staggered filing schedule for utilities to submit their resiliency plans, such as assigning certain utilities even-numbered years or odd-numbered years to file, to avoid stressing the resources of commission staff and OPUC.

Commission Response

The commission declines to modify the rule to mirror the procedural schedule for rate cases or establish a staggered filing schedule for resiliency plans. Until the commission has experience with evaluating resiliency plans, it is unclear to what extent these cases will resemble rate cases or what level of resources will be required to evaluate them. Further,

improving the resiliency of our electric system is an important priority across the state, and the commission does not have any basis to determine priorities or how to stagger the filing of these plans.

Proposed §25.62(d)(3)(A) – Denial of a resiliency plan

Subsection (d)(3)(A) states that denial of a resiliency plan is not a finding on the prudence or imprudence of a measure and that an electric utility may file a revised resiliency plan upon denial. Upon adoption, this provision was renumbered as §25.62(d)(5).

TEC recommended adding "denial or approval" to subsection (d)(3)(A) to ensure consistency with the reconciliation process under subsection (f)(4). TEC stated that its requested addition would ensure that the estimated costs in an approved resiliency plan are subject to reconciliation. Without this addition, utilities might argue that the estimated costs in a resiliency plan have been deemed prudent, nullifying the purpose of a full rate case to review the prudence of costs actually incurred during the prior rate period.

Commission Response

The commission declines to modify the rule because it is unnecessary. As TEC points out, all costs associated with the implementation of an *approved* resiliency plan are subject to prudency review. A utility must implement resiliency plans prudently, even if that requires the utility to implement it at a cost that is below the costs estimated in the resiliency plan. By contrast, the rule language stating that a *denied* resiliency plan is not a determination on the prudency of the measure is necessary to reflect statutory language. Further, a utility is

permitted to enact most potential resiliency measures outside of the context of a resiliency plan, subject to other applicable legal requirements. That a proposed measure was deemed inappropriate for inclusion in a resiliency plan – which could be determined for reasons unrelated to cost – does not *necessarily* mean that measure cannot be prudently implemented otherwise.

SPS recommended that the commission's approval of a resiliency plan carry a presumption of prudence of need and cost estimates for all projects detailed in the plan, including the distribution and transmission O&M. SPS asserted that presumptions of prudence are reasonable because the commission's pre-approval of a plan establishes functional authorization to implement projects without creating ambiguity around potential cost recovery on those approved projects, while also retaining a more formal review of recovery of costs that exceed those estimates, if needed.

Commission Response

The commission declines to modify the rule to include a presumption of the prudence of need. Unless the conditions for a good cause exception under subsection (e) are met, a utility is required by that subsection to implement the measures in its approved resiliency plan. Generally, complying with applicable legal requirements is presumed to be prudent. However, the inclusion of explicit language establishing a presumption of prudence may create uncertainty as to which aspects of the plan carry the presumption. For example, the commission does not agree with SPS's argument that any costs incurred up to the cost estimates in an approved plan can be presumed to be prudent. A utility has an obligation to ensure that all costs of implementing its resiliency plan are prudently incurred, even if that

means implementing a measure at a lower cost than the cost estimate included in the resiliency plan. Similarly, if an approved resiliency measure is to spend a predetermined amount of money on a certain action, the utility still has an obligation to use that pre-determined amount of money prudently. For example, if an approved resiliency measure is to spend $50,000 on additional vegetation management, whether the utility was able to complete a reasonable amount of vegetation management with those funds is subject to review.

Implementing any resiliency plan will require the utility to make many post-approval implementation decisions. Whether these decisions are made prudently is subject to review.

SPS provided, without discussion, language that would, in the event of a denial, require the commission to provide to the utility "a summary of the topics of concern that resulted in the resiliency plan denial."

Commission Response

The commission declines to require a summary of the topics of concern that resulted in the resiliency plan's denial. The order denying some or all of the measures in a resiliency plan will provide guidance to the utility. The utility can also seek informal feedback from commission staff or individual commissioners after the contested proceeding is over.

Proposed §25.62(d)(3)(B) – Modification of a resiliency plan

Subsection (d)(3)(B) allowed a utility to withdraw a modified resiliency plan without prejudice until the deadline for a motion for rehearing.

The commission removes this provision. If a utility disagrees with a modification made by the commission it may challenge that decision or request a rehearing using existing procedures.

Proposed §25.62(d)(4) - Commission Review of Resiliency Plan

Proposed subsection (d)(4) outlines the factors the commission will consider when reviewing a resiliency plan.

HEN recommended that the commission’s review include an analysis of the extent to which the plan incorporates the statutory policy set forth in PURA §39.001(d) to authorize competitive, rather than regulatory, methods to the greatest extent feasible.

Commission Response

The commission disagrees that the statutory policy set forth in PURA §39.001(d) is applicable to the evaluation of resiliency plans. PURA §39.001(a) explicitly excludes transmission and distribution services from the list of what should be determined by customer choices and the normal forces of competition. Further, PURA §38.078 specifically applies to regulated entities increasing the resiliency of their own systems, and also directs the commission to adopt rules to implement this statute. This more specific statutory mandate clearly takes precedence over the general language of PURA §39.001(d).

SWEPCO and ETI recommended striking all factors from the list of factors to be considered by the commission when reviewing the plan other than the ones mentioned in the statute, to more closely align the rule to the statute. Both also suggested replacing “may” with “shall” to reflect that the commission’s consideration of the list of factors is mandatory and not discretionary.

Commission Response

The commission declines to modify the rule as suggested by SWEPCO and ETI. PURA §38.078(e) specifically states that the “commission may approve a plan only if the commission determines that approving the plan is in the public interest.” This is a completely separate statutory requirement from the two statutory factors listed in PURA §38.078(e). The commission is not limited in what it may consider when evaluating the public interest, but the additional criteria provided in the rule provide some insight into what the commission may consider when evaluating public interest. This is also consistent with the commission’s general authority under PURA, which vests the commission with broad authority to oversee and supervise the electric utilities in the State of Texas. Specifically, PURA §14.001 grants the commission the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything that is necessary and convenient to the exercise of that power and jurisdiction.

Further, the commission also declines to modify the rule to replace “may” with “shall.” The use of “may” is intentional to indicate that consideration of these factors is permissive.

However, the commission does modify the rule to specifically identify which factors the commission is required to consider by statute and which factors are discretionary considerations of its public interest determination.

SPS stated that proposed subsection (d)(4) may create unintended consequences in the commission's determination of whether a utility's proposed resiliency plan is in the public interest. SPS explained that hardening a high-performing feeder may not directly "improve overall service reliability for customers," at least in normal operating conditions. Therefore, SPS recommended separating the resiliency-based evaluation criteria related to mitigating system restoration costs from reliability-based criteria related to improvement in overall service reliability for customers. Similarly, AEP suggested striking subsection (d)(4)(C) because it refers to a reliability issue, not a resiliency issue. SPS noted that use of the word "and" in subsection (d)(4)(B) implies that all four of the evaluation criteria must be met and recommended replacing "and" with "or."

Commission Response

The commission disagrees that any of the provisions of subsection (d)(4) will create unintended consequences in how the commission evaluates resiliency plans. This is a nonexclusive and permissive list of considerations. The commission retains discretion to assess the public interest as appropriate based on the facts and circumstances involved with any proposed resiliency measure.

The commission agrees with SPS and modifies the rule to replace "and" with "or," and makes other modifications to reflect commission intent.

TAEBA recommended the commission "define or require utilities to define 'areas of lower performance' as it relates to subsection (d)(4)." Additionally, TAEBA recommended that this definition "include areas with relatively high interruptions of service, consumer costs, and curtailment and congestion."

Commission Response

The commission declines to define areas of lower performance. Subsection (c)(2)(A)(i) requires the utility to explain whether it prioritized measures based on geographic region, and subsection (c)(2)(B)(iv) requires the utility to indicate whether the risks associated with resiliency events are specific to particular systems or geographic regions. These requirements provide some insight into whether areas of lower performance are prioritized. However, what constitutes lower performance will vary on a case-by-case basis and can best be determined in the context of a contested case.

Proposed §25.62(d)(4)(F) Consideration of more efficient and cost-effective means of addressing a resiliency event

Subsection (d)(4)(F) provides that the commission may consider whether there are other more efficient and cost-effective means of addressing a resiliency event during a resiliency plan review.

SWEPCO recommended deleting this subparagraph because these requirements are "unduly onerous" and would make the process of preparation and review of resiliency plans "burdensome" and result in "over-loading the commission with potentially redundant information."

Commission Response

The commission retains discretion to assess the public interest as appropriate based on the facts and circumstances involved with any proposed resiliency measure. This list merely serves to provide insight in what factors may be deemed relevant during this evaluation.

The commission disagrees with SWEPCO that this requirement would make resiliency plan preparation or review unduly burdensome. An essential consideration in whether a plan is in the public interest is whether there are superior options available. The commission broadens the language of this requirement to clarify intent.

Proposed §25.62(e) - Good cause exception

Under subsection (e), the commission will grant a good cause exception to the requirement that a utility must implement approved resiliency measures 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.

AEP commented that the commission should not limit the possible reasons for granting a good cause exception in its proposed rule because resiliency plan filings are new to Texas and a relatively new concept in general. AEP provided suggested language that would allow the commission to grant a good cause exception for any reason the commission deems appropriate.

Commission Response

The commission declines to modify the proposed rule to expand the reasons for which a good cause exception can be granted. PURA §38.078(f) provides the basis for the list of situations in which an electric utility may request a good cause exception. The only non-statutory situation listed--that the electric utility has a pending application for a revised resiliency plan that addresses the same resiliency events—is a logical extension of the commission's authority. Requiring a utility to implement a resiliency measure when it is preparing to implement an alternative measure would be unreasonable. The commission modifies the rule to reflect that the commission's ability to grant a good cause exception is permissive.

Proposed §25.62(f)(1) – Resiliency Cost Recovery Rider (RCRR) - Recovery of Operation and Maintenance Cost (O&M)

Proposed subsection (f)(1) establishes the resiliency cost recovery rider as a mechanism through which a utility can recover costs associated with a resiliency plan outside a base-rate proceeding.

SPS recommended the commission revise proposed subsection (f) to reflect eligibility of O&M cost recovery in the RCRR. Specifically, SPS recommended that the rule language specify that O&M, which is authorized to be deferred into a regulatory asset, and the amortization of the regulatory asset can be recovered through the DCRF or TCRF.

SPS also recommended the commission revise subsection (f) to authorize a utility to recover resiliency plan costs up to the commission-approved estimated costs included in the plan.

ETI and SWEPCO recommended the commission clarify that all costs eligible to be recovered include O&M costs and provided language consistent with their recommendation.

Commission Response

The commission modifies subsection (f) to reflect that a utility that does not request an RCRR may defer all or a part of the costs associated with implementing its plan for future recovery using a regulatory asset. The commission agrees with commenters that resiliency-related distribution O&M costs in an approved resiliency plan are eligible for deferral, but does not include the requested language, because it is unnecessary and may cause confusion regarding whether other unenumerated categories of expenses are eligible for deferral.

Houston recommended addressing reimbursement of rate case expenses in the proposed rule to allow parties participating in the Resiliency Cost Recovery Rider (RCRR) proceedings to receive reimbursement for reasonable rate case expenses.

Commission Response

The commission disagrees with Houston that the proposed rule must include language that addresses reimbursement of rate case expenses for parties participating in the RCRR cases. The statutory language does not require such a provision, and the commission's other rider-related rules do not include such provisions. For consistency among rules, the commission declines to include language that addresses rate case expense recovery in the RCRR.

ARM and TEAM proposed a change to subsection (f)(1) to require electric utilities to provide REPs with notice no later than 45 days before a new or updated RCRR is effective, and that new or updated RCRRs have effective dates that are coordinated with other rate changes by a utility implementing a new or updated RCRR. ARM explained that a 45-day notice requirement is historical standard practice for implementing incremental revisions to tariff riders such as the DCRF and EECRF and should be employed with the RCRR to ensure REPs have sufficient time and certainty to implement RCRR-related rate changes so that customer pricing remains accurate. Similarly, TEAM remarked that such a filing is necessary because the commission is statutorily prohibited from approving an RCRR that authorizes cost recovery before a utility's resiliency-related investments are used and useful. Because of this prohibition, TEAM asserted, at the time a resiliency plan is approved, it is unlikely that a proposed utility plan would include, or that the commission could approve, "a date-certain for the RCRR."

Commission Response

The commission agrees with ARM and TEAM that providing sufficient notice to REPs before a new or updated RCRR is effective is important, so REPs have sufficient time to implement any related changes. The commission adds the relevant language to the rule accordingly.

TCA & ASC recommended that proposed subsection (f) authorize "non-utility options" to be eligible for utility cost recovery, such as contracting with third parties and customers to acquire and implement resiliency measures.

Commission Response

The commission declines to modify the rule as proposed by TCA & ASC because providing ratepayer dollars to support the activities of entities that are not regulated by the commission is beyond the scope of this rulemaking.

Proposed §25.62(f)(1)(A)(ii) – Provision to amend RCRR

Proposed subsection (f)(1)(A)(ii) authorizes an electric utility with an existing RCRR to apply to amend the RCRR to include additional costs associated with an updated resiliency plan under PURA §38.078(g).

CenterPoint and TNMP recommended that proposed subsection (f)(1)(A)(ii) be revised to authorize an electric utility to apply to amend the RCRR once a year to include additional costs incurred by the utility in the prior year.

ETI recommended that utilities be authorized to update the RCRR up to twice a year, similar to the process for the DCRF and TCRF, to recover additional invested capital. ETI explained that if the rule does not authorize more frequent updates to the RCRR, a utility would be forced to forego recovery until an amendment is permitted at the end of the three-year period prescribed by proposed subsection (c). ETI asserted that such an outcome is contrary to the intent of PURA §38.078(i) that allows for recovery of distribution investments made by electric utilities to implement a resiliency plan via a rider. ETI also suggested including language limiting the scope of proceedings for such an amendment to whether the additional resiliency-related distribution invested capital will be placed in service within 90 days of the application and whether the electric utility has correctly calculated the new rider rates.

ETI also recommended procedural additions that would require an electric utility to make an update filing within 90 days after the application and would require commission review of the update within 30 days from the date the update was filed. The update filing would state the final amount of incremental resiliency-related distribution invested capital and the resulting rider rates to be implemented.

Commission Response

The commission declines to modify the rule to permit a utility to update its resiliency rider multiple times, because PURA §38.078(i) only allows for a utility to request an RCRR as part of its resiliency plan. Unlike PURA §§36.210(d), 35.004(d), and 39.905(b-1), PURA §38.078 does not authorize updates or amendments to a resiliency rider. However, at the time a resiliency plan is approved, a utility has not yet incurred any resiliency-related expenses. To facilitate the use of this rider, the commission adds subsection (f)(1)(A)(iv), which establishes a process to allow a utility to apply for approval of RCRR rates.

Concurrent with the adoption of HB 2555, the Texas Legislature also adopted SB 1015, which increased the frequency with which a utility can file a DCRF update to twice a year. If the commission also allowed a utility to update its RCRR once or twice a year, as requested by commenters, this would result in three or more proceedings every year for each utility related to recovery of distribution expenses. This would impose an unnecessary burden on

commission staff and the participants in utility rate proceedings, and on REPs required to implement these rate changes.

The combined result of this rule and the new statutory provisions related to DCRFs provides ample opportunities for a utility to recovery resiliency-related distribution expenses. A utility can seek recovery of resiliency-related expenses twice per year in its DCRF, in a base-rate case proceeding, and either one additional time every three years with an RCRR address or it may record its costs in a regulatory asset for future recovery.

Proposed §25.62(f)(1)(A)(iii) – Effective date of RCRR

Proposed subsection (f)(1)(A)(iii) prohibits an RCRR from taking effect until all facilities with costs included in the RCRR begin providing service to the electric utility's customers.

Oncor stated that the proposed language establishes a process where a RCRR would not go into effect until all facilities associated with a resiliency plan are in service. Resiliency plan implementation could span a multi-year period, which would delay timely recovery of resiliency-related costs. Oncor recommended revising proposed subsection (f)(1)(A)(iii) to align with the statutory language of PURA §38.078(i).

SWEPCO and SPS recommended deleting proposed subsection (f)(1)(A)(iii), because resiliency projects may be implemented on transmission and distribution assets that are already in service. SWEPCO and SPS commented that, as proposed, the language limits application and recovery to new infrastructure only, which is contrary to the intent of the rule. SPS further noted that, because the proposed rule provides for "a prudency finding in advance" and a reconciliation process after implementation of a resiliency plan, cost recovery should therefore be concurrent with investment to both prevent regulatory lag and provide the electric utility with adequate funding to make incremental investments.

OPUC commented that a utility should not be eligible for recovery until the utility has incurred some costs in implementing a plan that has been deemed prudent by the commission.

Commission Response

The commission agrees that resiliency measures are not limited to new facilities and modifies the rule accordingly.

The commission disagrees that the rule provides for a "prudence finding in advance." While the implementation of approved resiliency measures is legally required (and, therefore, reasonable to implement), a utility must implement those measures prudently. PURA §38.078(h) expressly states that an "electric utility's implementation of a plan may be reviewed…[and]…costs to implement an approved plan [that are] imprudently incurred or otherwise unreasonable…are subject to disallowance."

Proposed §25.62(f)(1)(A)(iv) – Provision to include RCRR costs in a DCRF or base-rate proceeding

Subsection (f)(1)(A)(iv) authorizes an electric utility to include its RCRR costs as part of its next DCRF or base-rate proceeding, provided that the electric utility requests that RCRR rates be set to zero as of the effective date of rates resulting from that proceeding.

AEP recommended subsection (f)(1)(A)(iv) be revised to clarify when "the rider continues and when rider rates are zeroed out." Specifically, AEP provided language that would make more explicit the requirement for an electric utility requesting RCRR costs to be included in its next DCRF or base-rate proceeding to also request its RCRR rates be set to zero as of the effective date of the DCRF or base-rate proceeding. Moreover, if such a request is not made, the RCRR cost recovery would "continue through the rider factors." AEP provided redlines consistent with its recommendations.

Commission Response

The commission declines to make the requested changes. The proposed language properly requires that RCRR rates be set to zero upon the effective date of subsequent DCRF or base rates. Establishment of a new RCRR allows a utility to reduce the regulatory lag associated with recovering resiliency-related costs. However, no public interest is served by allowing multiple riders to remain in effect that recover the same types of costs where such cost recovery can be reasonably consolidated into existing rates. Requiring that RCRR rates be zeroed out, while allowing the utility to include unrecovered RCRR costs in its base rates or DCRF rates, does not impair a utility's ability to recover resiliency-related costs. Further,

doing so provides benefits in the form of reduced administrative costs for the REPs that must implement the rates, and the reduced potential for customer confusion due to a proliferation of otherwise unnecessary rate riders.

Proposed §25.62(f)(1)(B) – Calculation of RCRR Rates

Proposed subsection (f)(1)(B) prescribes the RCRR rate methodology for each rate class.

Houston recommended the commission adopt RCRR rate filing instructions and required schedules and workpapers to ensure uniformity in RCRR applications. Alternatively, if the commission declines to adopt more specific and uniform filing requirements for an RCRR, Houston recommended the proposed RCRR and resiliency-related DCRF formulas in the proposed rule be made clearer with more detailed definitions of the inputs, as has been done previously under 16 TAC §25.239 and §25.243.

OPUC recommended the commission use the formula included in the Ernest Orlando, Lawrence Berkeley National Laboratory's report, "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States," for calculating the cost of an outage to the residential customer class when developing a reasonable budget to use when the commission reviews an electric utility's RCRR.

Commission Response

The commission declines to add rule language addressing an RCRR rate filing package because it is beyond the scope of this rulemaking. The commission may develop a rate filing

package at a later time. The commission also declines to modify the rule as requested by OPUC. The considerations involved in evaluating the cost and value of different resiliency measures may vary, and the commission will not limit this evaluation to a single formula at this time.

Proposed §25.62(f)(1)(B)(ii)(II) and (IV) and (f)(1)(B)(iii) – Load growth adjustment

Proposed subsection (f)(1)(B)(ii)(II) prescribes the methodology for calculating the value of the total RCRR Texas retail revenue requirement. Proposed subsection (f)(1)(B)(ii)(IV) prescribes the methodology for calculating the incremental distribution capital cost recovery value. Proposed subsection (f)(1)(B)(iii) describes the terms used in the calculation.

TNMP AEP, CenterPoint, and ETI recommended removing load growth adjustment as a component of the cost calculation provisions within proposed subsection (f)(1)(B)(ii) and (iii). TNMP, AEP, SWEPCO, CenterPoint and ETI asserted that the statute does not contemplate such an adjustment to be included in the RCRR unlike the reference for such an inclusion that is explicit in PURA §36.210 for the DCRF. Specifically, TNMP recommended the incremental distribution capital cost recovery and growth in billing determinants variables, IDCCR and $\%GROWTH_{CLASS}$ respectively, be omitted from the rule. TNMP explained that including a load growth adjustment in the RCRR prevents an electric utility from recovering all applicable costs permitted by PURA §38.078. TNMP also commented that there is no statutory or other basis for including a load growth adjustment in the RCRR.

ETI explained that when similar cost recovery statutes did not include a load growth adjustment, the corresponding commission rules correctly did not include one either. ETI referenced PURA §36.209 and 16 TAC §25.239, relating to Transmission Cost Recovery Factor for Certain Electric Utilities for the non-ERCOT TCRF; PURA §35.004(d) and 16 TAC §25.192(h), relating to Transmission Service Rates, for ERCOT TCOS; and PURA §36.214 and 16 TAC §25.248, relating to Generation Cost Recovery Rider. In contrast, ETI pointed out that 16 TAC §25.243, relating to Distribution Cost Recovery Factor (DCRF) appropriately includes a load growth adjustment because one is required under the DCRF enabling statute, PURA §36.210. ETI contended that the intent of a load growth adjustment, which is to ensure that a utility can provide the same level of service to new customers, is contrary to the intent of resiliency plans, which is to enhance the level of electric service provided to customers through resiliency measures implemented over a period of years. Accordingly, the recovery of incremental revenues attributable to load growth would be insufficient to recover resiliency plan costs. ETI reasoned a resiliency plan application proceeding is not the appropriate venue to assess whether a utility is recovering excessive revenues. Instead, such an analysis should be reserved for a base-rate case, where all of a utility's revenues and costs are reviewed. Lastly, ETI noted that the use of "up-to-date billing determinants" in calculating RCRR rates coupled with the reconciliation proceeding in the proposed rule should be sufficient to mitigate temporary over-recovery of these costs.

SWEPCO stated that a load growth adjustment is not appropriate for an RCRR because costs recovered for a resiliency plan are a new category of costs that are not currently being recovered in a utility's base rates. Similarly, CenterPoint noted that the formula for establishing the RCRR would be set to recover costs associated with new facilities and equipment placed into service under the resiliency plan and were not included in the utility's most recent base-rate proceeding. Upon amendment of an RCRR any remaining costs associated with the initial investments under the resiliency plan, including incremental investments such as load growth, would be recovered over an increased amount of billing determinants and therefore making a load growth adjustment unnecessary.

Similar to ETI, Oncor recommended proposed subsection (f)(1)(B)(ii)(II) be reviewed to ensure there is no double counting of any load growth adjustments due to potential "timing or synchronization issues associated with moving a growth adjusted RCRR into a subsequent DCRF application, which will then also be growth adjusted." Oncor explained the proposed rule does not include the process of accounting for the RCRR in a DCRF proceeding which, depending on the manner of execution, could lead to such overlap.

Commission Response

The commission declines to modify the rule to remove the load growth adjustment in the RCRR for the following reasons. PURA §38.078(l) provides that the commission may only include "costs that are not already being recovered". Therefore, the commission cannot ignore the fact that load growth subsequent to a base-rate proceeding may lead to a utility recovering significant revenues associated with costs beyond the level of costs used to establish base rates or DCRF rates. Further, the requirement in PURA §36.051 that a utility's "overall revenues" be considered in establishing rates requires a consideration of the growth in billing units and associated revenues. Failure to do so would result in rates that exceed the level necessary to provide the utility a reasonable opportunity to earn a reasonable

return in excess of its reasonable and necessary expenses. ETI's assertion regarding the intent of load growth adjustments adopted by the commission is therefore incorrect. Load growth is accounted for in establishing DCRF rates under 16 TAC §25.243, PCRF rates under 16 TAC §25.238, and interim TCOS rates under 16 TAC §25.192, contrary to ETI's assertion. Since resiliency-related costs may be included in DCRF rates and interim TCOS rates, failing to include a load growth adjustment in establishing RCRR rates would lead to an unreasonable discrepancy between resiliency cost recovery methods.

The use of up-to-date billing determinants in calculating RCRR rates is reasonable and appropriate. However, such an approach does not fully account for the fact that incremental rate revenues may be available to the utility to recover some portion of incremental resiliency costs. SWEPCO's and CenterPoint's assertions regarding the fact that resiliency-related costs are a new category of costs are similarly inapposite, as incremental rate revenues are fungible, and may be used to recover any category of incremental utility costs. Regarding Oncor's concerns, the reconciliation of resiliency costs in a subsequent base-rate proceeding may reasonably include a review of the accounting for any RCRR costs into subsequent DCRF rates. The commission adds language to subsection (f)(4)(D) requiring reconciliation information be included as part of a base-rate application to facilitate such review. The commission further modifies subsection (f)(1)(B)(ii)(VI) for consistency with the load growth adjustment provision included in 16 TAC §25.243, noting that a utility may apply for a base rate increase in the event that it is under-recovering base rate-related costs.

Proposed §25.62(f)(1)(B)(ii)(III) – RCRR class allocation factor

Proposed subsection (f)(1)(B)(ii)(III) prescribes the methodology for calculating the RCRR class allocation factor for a rate class.

Oncor recommended that the commission revise the formula in proposed subsection (f)(1)(B)(ii)(III) to $ALLOC_{C\text{-}CLASS} = ALLOC_{RC\text{-}CLASS}$ for administrative efficiency and to reduce potential disputes. Oncor noted that, as proposed, the formula for the RCRR class allocation factor reflects growth after the electric utility's most recent base-rate case, which may be a different methodology used for allocation in the base rate case itself.

Commission Response

The commission declines to make the requested modification. The proposed adjustment is consistent with a similar provision adopted in 16 TAC §25.248. The adjustment to class allocation factors is important to reasonably account for changes in relative load growth between classes subsequent to the utility's most recently completed base-rate proceeding. Failing to make such an allocation adjustment could lead to the potential for significant rate shock in a subsequent base-rate proceeding when allocation factors are updated based on then-current load.

Proposed §25.62(f)(1)(B)(ii)(V) – Calculation of RCRR Rates

Proposed subsection (f)(1)(B)(ii)(V) prescribes the methodology for calculating distribution revenues by rate class based on net distribution invested capital from the most recently completed comprehensive base-rate proceeding.

ETI, TNMP, AEP, and CenterPoint noted that the formula in proposed subsection (f)(1)(B)(ii)(V) incorrectly refers to §25.239(d)(1), the non-ERCOT TCRF rule, as the cross-reference for variable definitions. Commenters stated the correct citation is the DCRF rule under §25.243(d)(1).

Commission Response

The commission agrees and corrects the reference accordingly.

Proposed §25.62(f)(1)(B)(iii)(III)(-d-) – DCRFLGA – Distribution Cost Recovery Factor

Proposed subsection (f)(1)(B)(iii)(III)(-d-) defines the DCRF load growth adjustment value as the value in the most recent DCRF proceeding for the utility since its most recently completed base-rate proceeding, or zero if there are no DCRF proceedings since the utility's most recently completed base-rate proceeding.

AEP recommended deleting subsection (f)(1)(B)(iii)(III)(-d-) because it is reflective of a load growth adjustment which is neither required by PURA §38.078 nor appropriate for an RCRR due to the availability of the reconciliation process and because the rider already requires the use of up-to-date billing determinants.

Commission Response

The commission declines to make the requested modification because the proposed load growth adjustment is retained in the adopted rule.

Proposed §25.62(f)(1)(C) – Class allocation factors

Proposed subsection (f)(1)(C) provides that, 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.

OPUC stated that the use of the baseline class allocation factor referenced in subsection (f)(1)(C) may not be the most appropriate standard because residential ratepayers are more likely to bear a greater cost burden for resiliency plans that benefit all transmission and distribution customers.

OPUC further remarked that "residential customers under such [a] model would pay in recovery the same percentages that they pay in the base-rate for their electricity usage for these resiliency plans."

Commission Response

The commission declines to modify the rule language. The baseline class allocation factor is the appropriate starting basis for allocating resiliency-related distribution costs because it is the most recent commission-approved determination as to class responsibility for distribution costs. Resiliency-related transmission costs will not be included in the RCRR.

New §25.62(f)(1)(E) and (F) – Notice to REPs of RCRR effective date

TEAM recommended subsection (f)(1) be revised to add new subparagraphs (E) and (F) which would require an electric utility to file its RCRR tariff pages with the commission with a notice of the effective date for the Rider at least 45 days before the stated effective date. TEAM provided redlines consistent with its recommendation.

Commission Response

The modifications made to subsection (f)(1)(A)(v) requiring utilities to provide notice of the approved rate and effective date of the approved rates to retail electric providers should address TEAM's concerns.

Proposed §25.62(f)(2) – Resiliency Cost Recovery Factor

Proposed subsection (f)(2) prescribes a mechanism for an electric utility to recover certain resiliency-related costs deferred as a regulatory asset through an RCRF rate as part of a TCRF proceeding.

ETI recommended subsection (f)(2) be deleted on the basis that it is unnecessary complex and misinterprets PURA §38.078(i). ETI observed that the proposed language authorizes a utility that elects to not apply for an RCRR and instead defers distribution-related resiliency plan costs, to apply for a different rider, the TCRF, which is a transmission-related proceeding. ETI interpreted the authorization under PURA §38.078(k) to use cost-recovery alternatives such as the DCRF or TCRF for recovery of eligible resiliency-related costs to not include distribution-related resiliency costs deferred under PURA §38.078(i). ETI asserted that, aside from a base-rate proceeding, PURA §38.078(i) provides for only two alternative recovery alternatives for distribution-related resiliency plan implementation costs: the RCRR under PURA §38.078(i) and the deferral of distribution-related resiliency costs under PURA §38.078(k). ETI accordingly concluded that deferred distribution-related resiliency plan costs should neither be eligible for another rider, nor be undertaken in a transmission-related proceeding.

Commission Response

The commission agrees with ETI and removes proposed subsection (f)(2).

Proposed §25.62(f)(3) and (f)(3)(A) – Deferral of resiliency plan costs in a regulatory asset

Subsection (f)(3) prescribes a mechanism for an electric utility to request to recover certain resiliency-related costs deferred as a regulatory asset as part of a DCRF proceeding. Subsection (f)(3)(A) authorizes an electric utility that is eligible to request a DCRF, to request to include in its DCRF application the resiliency-related costs deferred as a regulatory asset in its DCRF rates, notwithstanding the existing requirements of §25.243.

ETI noted that the proposed rule refers to the potential of cost deferral through a regulatory asset but neither explicitly addresses the circumstances for authorization of a regulatory asset nor prescribes the scope of such a deferral. ETI and SWEPCO requested to revise this subsection to authorize a utility that does not apply for RCRR to defer all or a portion of distribution-related costs including distribution related operation and maintenance expenses for future recovery as a regulatory asset. ETI and SWEPCO stated that such costs would include, in a manner consistent with PURA §38.078(k), depreciation expenses and carrying costs at the utility's weighted average cost of capital established in the utility's most recent base-rate proceeding. Both commenters provided redlines consistent with their recommendation.

TNMP recommended subsection (f)(3)(A) be revised to include the depreciation expense and carrying costs at the utility's weighted average cost of capital established in utility's most recently completed base-rate proceeding as part of resiliency-related costs eligible to be deferred as a regulatory asset.

AEP, SWEPCO, and CenterPoint recommended the references to §25.234 in §25.62(f)(3)(A) be revised to correctly refer to §25.243.

Commission Response

The commission agrees and has modified the rule language accordingly. The commission further clarifies the language in proposed subsection (f)(3)(A), that a utility with a resiliency-related regulatory asset must include a request for recovery of the asset as part of any DCRF proceeding. This subparagraph is renumbered as (f)(2)(A).

Proposed §25.62(f)(4)(A) – Reconciliation of RCRR

Subsection (f)(4)(A) establishes the process in which resiliency-related amounts recovered through rates are subject to reconciliation and commission review in the electric utility's next base-rate proceeding after the effective date of the rates.

TNMP requested for §25.62(f)(4)(A) to be amended to clarify that actual costs incurred in implementing a resiliency plan will not be deemed unreasonable on the sole basis that actual costs are different from estimates provided in an electric utility's resiliency plan. TNMP reasoned that since actual costs that equal estimated costs are not automatically deemed to be reasonable, a presumption of unreasonableness should not be established when actual costs differ from estimated costs. TNMP also noted that, because future estimates are inherently uncertain, it is impossible to know with absolute confidence what the actual costs are until they are incurred.

SPS provided draft language to suggest that the commission only consider whether costs in excess of those in the utility's approved plan are reasonable, necessary, and prudent.

Commission Response

The commission agrees that the fact that actual resiliency-related costs may differ from estimated costs is not a sufficient basis, on its own, to deem such costs as unreasonable. However, additional rule language is not necessary.

Proposed §25.62(f)(4)(B) – Refund of unreasonable, unnecessary, or imprudent rates

Subsection (f)(4)(B) provides that any amounts recovered through rates previously approved under §25.62 that are found to have been unreasonable, unnecessary, or imprudent, must be refunded with carrying costs plus the corresponding return and taxes.

OPUC recommended a cost cap for resiliency plans be introduced in proposed subsection (f)(4)(B) to avoid unnecessary cost overruns and exponential rate increases to ratepayers. OPUC also recommended the commission impose "monetary restrictions" and other requirements when an electric utility implements resiliency measures as necessary pre-conditions for commission approval of a resiliency plan. Specifically, such requirements would be aimed to "ensure that the measures included in their plans actually function as intended to prevent the emergencies they are intended to mitigate."

Commission Response

The commission declines to modify the rule to require cost caps. However, the rule does not prevent a resiliency plan from including cost caps or other preconditions for the implementation of a particular resiliency measure. Further, the commission has discretion to modify resiliency plans, which includes the ability to impose costs caps or other preconditions, where appropriate.

OPUC also recommends that the commission should modify the rule to require that any expenses associated with resiliency measures that fail to provide their intended resiliency benefits be refunded to customers with carrying costs. OPUC argued that this will incentivize utilities to ensure that the methodologies and technologies included in their resiliency plans are the best suited to mitigate the actions they are intended to prevent. OPUC further argues that without a definable consequence a utility resiliency measure may fail, and yet the utility will be allowed to recover rates from ratepayers for inadequate measures included in a plan.

Commission Response

The commission declines to modify the rule to require utilities to refund any expenses associated with resiliency measures that fail to provide their intended resiliency benefits. Such a requirement would serve as a strong disincentive for utilities to propose resiliency plans or to design their plans to address the most extreme resiliency challenges their systems face, because attempts to address these challenges have an inherently higher chance of

failure. This is contrary to the legislative intent of HB 2555, which indicates a strong state interest in encouraging utilities to design resiliency plans.

According to the legislative findings of the uncodified portions of HB 2555, "it is in the state's interest to promote the use of resiliency measures…[and] for each electric utility to seek to mitigate system restoration costs to and outage times for customers." The Legislature further found that "all customers benefit from reduced system restoration costs."

However, the commission does agree that each proposed resiliency measure needs to be scrutinized carefully before it is approved to ensure that it relies upon methodologies and technologies that are well-suited to address the risks it is designed to address. If the commission had determined that it is in the public interest to implement a resiliency measure – which by its very nature requires some amount of speculation – it would be unjust to deny recovery if the measure fails to perform as expected. This is particularly true, because once a resiliency plan is approved, a utility is required to implement its measures.

New §25.62(f)(4)(C) – Reasonableness of actual costs when different from estimated costs

Given the future-oriented nature of resiliency plan measures, Oncor recommended new subsection (f)(4)(C) be added to the rule to make clear that a utility's costs will not be disallowed simply for executing the approved plan. Specifically, new subsection (f)(4)(C) would state that actual costs will not be deemed unreasonable by the commission solely on the basis of actual costs differing from estimated costs provided in the resiliency plan. Oncor noted that this addition would merely prevent higher than estimated actual costs from being the sole, determinative factor for a disallowance of costs incurred in implementing resiliency plan measures. Oncor provided redlines consistent with its recommendation.

Commission Response

As previously noted, the commission agrees that the fact that actual resiliency-related costs may differ from estimated costs is not a sufficient basis, on its own, to deem such costs as unreasonable. However, additional rule language is not necessary.

New §25.62(f)(5) – RCRR's effect on electric utility's financial risk and rate of return

TIEC and OPUC recommended that the proposed rule mirror provisions in the TCRF and DCRF rules that explicitly allow the commission to account for the impact of interim recovery mechanisms on the utility's financial risk and rate of return when settling base rates. TIEC commented that the rule should explicitly address this relationship to account for the reduced risk associated with the RCRR in conjunction with option for a utility to defer costs to future proceedings. TIEC provided redlines consistent with its recommendation.

Commission Response

The commission agrees that the reduced regulatory risk and reduced regulatory lag associated with the rule may provide a reasonable basis to establish base rates using a lower-than-otherwise rate of return for the utility. However, such considerations are within the commission's broader authority to establish just and reasonable rates, and no specific rule language is necessary.

New §26.52(f)(5) - Recovery of and on assets prudently retired in furtherance of a commission-approved plan

ETI recommended adding language to allow utilities to recover on undepreciated assets prudently retired or replaced as part of a resiliency plan. ETI provided redlines consistent with its recommendation.

Commission Response

The commission declines to add the recommended language to the rule because this is contrary to the precedent. Refer to the commission response under subsection (b)(4) resiliency-related distribution invested capital that explains the precedent and provides details of the modifications made to the definition of RDDEPR in subsection (f)(1)(B)(iii)(II)(-c-) to clarify commission's intent.

Proposed §25.62(g) Reporting requirements

Proposed subsection (g) establishes reporting requirements for utilities with a resiliency plan approved by the commission.

HEN recommended adding a reporting requirement related to the implementation of resiliency measures that will removing barriers to entry for DERs, microgrids, and other competitive solutions.

Commission Response

The commission declines to add a reporting requirement to specifically track measures that remove barriers to DERs, microgrids, and other competitive resiliency solutions. Removing

barriers for these technologies is not a primary objective of this rulemaking, and it would be inappropriate and unduly burdensome to impose this requirement on every resiliency plan.

Oncor, TNMP, and SWEPCO suggested modifying the date by which a report must be filed. Oncor and TNMP suggested that the annual resiliency plan report be due by May 1 of each year, "beginning the year after the plan is approved," while SWEPCO suggested that the due date of the annual resiliency plan report be tied to the anniversary of the plan's approval by the commission.

Commission Response

The commission agrees with Oncor and TNMP that the annual report should be due the year after the plan is approved and modifies the rule language accordingly.

Proposed §25.62(g)(2) and (g)(2)(B) – Resiliency Benefit Update

Proposed subsection (g)(2) requires a utility to provide an update on the resiliency benefits until the third anniversary of a fully implemented plan. Proposed subsection (g)(2)(B) requires a utility to evaluate the effectiveness of each implemented resiliency plan measure in addressing resiliency events by comparing the actual performance of the measure to projected performance.

SWEPCO recommended removing subsection (g)(2) completely, and Oncor recommended removing the last sentence of subsection (g)(2)(B). Both commenters indicated that the probability of certain resiliency events cannot be accurately predicted, and the effectiveness of steps taken to mitigate risks from those events cannot be accurately measured. Oncor offered the example of a foot patrol intended to provide security against physical attacks. Oncor indicated that it is impossible to evaluate how many potential attackers were potentially deterred by these foot patrols.

Commission Response

The commission declines to remove the rule language as recommended by SWEPCO and Oncor. The rule provides a utility broad discretion to recommend whatever metric or criteria is believes is best suited for the evaluation of each resiliency risk, including indicating that a particular measure cannot be evaluated quantitatively. Consistent with subsection (a)(1), the commission will evaluate any proposed criteria or metrics, and how they can be reported on, pragmatically.

Proposed §25.62(g)(2)(C) Expected impact on system restoration costs, outages, and service reliability

Proposed subsection (g)(2)(C) requires a utility to report annually on the expected impact of implemented resiliency plan measures on system restoration costs, outages, and service reliability for customers.

SPS commented that the term "reliability" in this subparagraph conflates resiliency and reliability issues and recommended removing most of the requirement.

Commission Response

The relevance of overall service reliability to each resiliency measure will vary. The commission modifies the rule to apply the requirements of subsection (g)(2)(C) "as appropriate for each measure."

Houston stated that the SAIDI, SAIFI, and CAIDI information described in subparagraph (C) should be included in a utility's resiliency benefit update. Accordingly, Houston requested the word *may* in subparagraph (C) be changed to *must*.

Commission Response

The commission declines to require SAIDI, SAIFI, and CAIDI information in the annual report. This information may not be appropriate for the evaluation of every type of resiliency measure. For instances in which this information is relevant for one or more proposed resiliency measures, the utility may include these as evaluation metrics in their resiliency plan or commission may modify the resiliency plan to require those indices as evaluation metrics for those measures. Accordingly, the commission removes this permissive language from the rule. If SAIDI, SAIFI, and CAIDI statistics are added to a resiliency plan as an evaluation metric, if appropriate, these statistics will be required to be reported at the feeder level, include all interruption classifications, and include the number of critical and chronic customers on each feeder.

Adopted §25.62(g)(3) – Resiliency plan updates

The commission adds a provision requiring a utility to include in an application to update a resiliency plan any information contained in resiliency benefit update related to any previously approved resiliency measures designed to address the same or similar resiliency risks.

Proposed §25.62(g)(3) - Reporting requirements

Proposed subsection (g)(3) requires utilities to maintain records associated with resiliency plans.

AEP suggested that the commission set a time limit of five years on retention of records associated with resiliency plans, noting that five years is consistent with other record retention requirements and policies.

Commission Response

The commission agrees with the commenter and modifies the rule text to require records be retained for five years, beginning the year after the approval of the plan. The commission also renumbers this requirement as subsection (g)(4).

The amended 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 and §38.078 which allows electric utilities to submit to the commission, plans to enhance transmission and distribution system resiliency.

Cross reference to statutes: Public Utility Regulatory Act §§14.002, and 38.078.

§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.

This agency certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that §25.62, relating to Transmission and Distribution Resiliency Plans, is hereby adopted with changes to the text as proposed.

Signed at Austin, Texas the _____ day of January 2024.

PUBLIC UTILITY COMMISSION OF TEXAS

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KATHLEEN JACKSON, INTERIM CHAIR

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LORI COBOS, COMMISSIONER

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JIMMY GLOTFELTY, COMMISSIONER